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Potential Abatement Production and Marketing of Byproduct Sulfuric Acid in the U.S.

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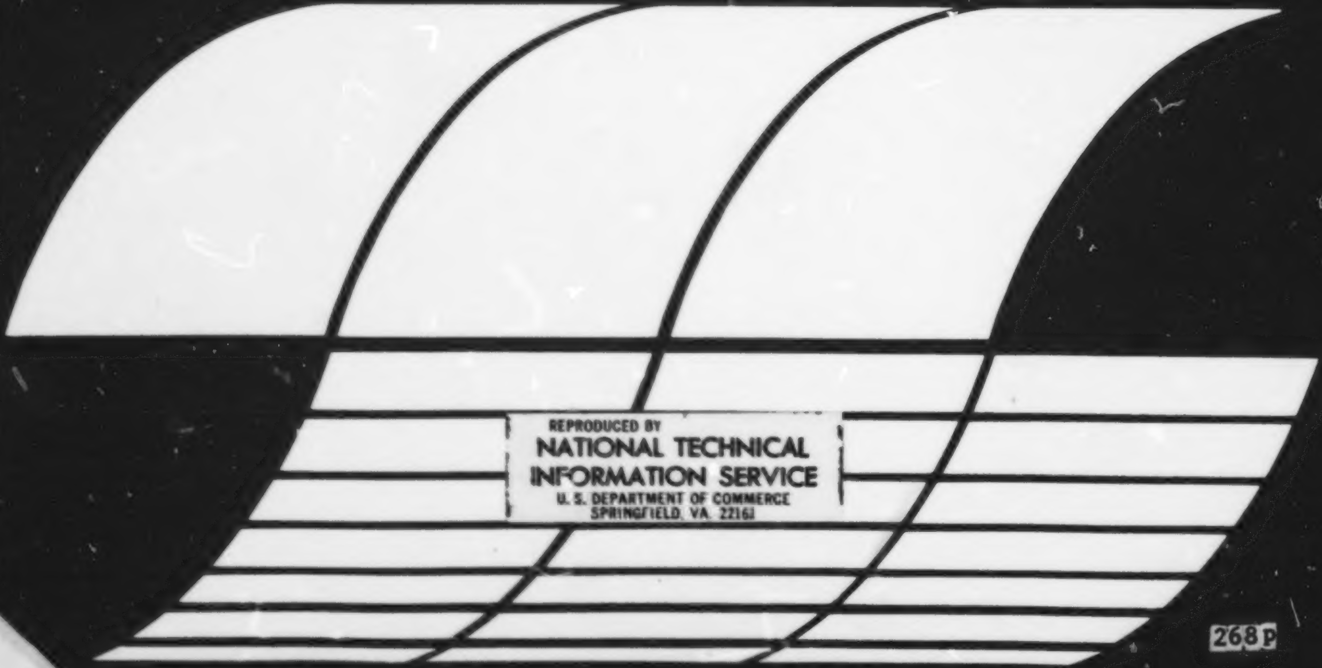

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Sulfur	Boilers	Clean Fuel		13A
Byproducts	Flue Gases		14B	21B
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ABSTRACT

Air quality regulations require control of sulfur oxides emissions from power boilers. Recovery of sulfur in useful form would avoid waste disposal and conserve natural sulfur and natural gas used to mine sulfur. Marketability of byproducts is an uncertainty. This U.S. Environmental Protection Agency-sponsored study was conducted by the Tennessee Valley Authority to evaluate market potential for sulfur and sulfuric acid byproducts. A cost model was developed to estimate the least-cost compliance method from three alternatives: (1) selecting a clean fuel strategy, (2) selecting a limestone-throwaway scrubbing technology, or (3) selecting a sulfuric acid or sulfur-producing scrubbing technology. For plants where production of byproducts was the economic choice, a market simulation model was used to evaluate distribution of byproducts in competition with existing markets. Significant amounts of sulfuric acid could be produced from sulfur oxides in power plant flue gas and sold in competitive markets.

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ABBREVIATIONS, GLOSSARY, AND GENERAL CONVERSION FACTORS

ABBREVIATIONS

ACFL	Alternative clean fuel level
BOM	U.S. Bureau of Mines
CDS	Compliance Data System
CENTRE	Centre Mark Company
EDS	Energy Data System
EPA	U.S. Environmental Protection Agency
FGD	Flue gas desulfurization
FIPS	Federal Information Processing Standard
FPC	Federal Power Commission
G[a]	Billion (10^9)
k[a]	Thousand (10^3)
M[a]	Million (10^6)
MES	Mutually exclusive set
NEDS	National Emissions Data System
NRBT	National Rate Basis Tariff
NSPS	New Source Performance Standards
PEDCo	PEDCo-Environmental Specialists, Inc.
SIP	State Implementation Plan
SPLC	Standard Point Location Code
SRI	Stanford Research Institute
TVA	Tennessee Valley Authority

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a. Although British units are used in this report, the International System of Units (SI) symbols are used in transition to the metric system.

GLOSSARY

Alternative clean fuel level: The value assigned to premium price for fuel that will meet the sulfur oxide emission standard.

Avoidable costs: An estimation of the production costs over the long-term planning horizon that could be avoided by closing an existing acid plant assuming abatement acid would be available in amounts equal to the plant production capacity (330 days/yr). Salvage value of the plant is assumed to be equal to the salvage cost.

Capacity factor: Throughout this study capacity factor is defined and calculated as the ratio of the annual quantity of heat consumed in the boiler in comparison to the quantity that would have been consumed if the boiler operated at rated capacity (full load) for the entire year (8760 hr). For steam electric boilers, this definition is equal to capacity factors calculated in terms of either steam or electricity generation.

Centre Mark Company: Source of geographic information on locations in the U.S., including latitudes, longitudes, county data, and various other information related to over 100,000 locations.

Commodity column tariff: Tariff publishing Docket 28300 commodity rates which are exceptions to the class rates.

Competitive equilibrium solution: Represented by the long-run break-even market condition which comes at a critical price where identical firms just cover their full competitive costs. At a lower long-run price, firms would leave the industry until prices return to the critical equilibrium level; at higher long-run price, new firms would enter the industry replicating what existing firms are doing and thereby force market price back down to the long-run equilibrium price where all competitive costs are just covered.

The long-run competitive equilibrium for sulfur and sulfuric acid market conditions in this study is simulated by minimizing the total cost of both the sulfuric acid and power plant industries, subject to the condition that the acid production demand is still met either from traditional sulfur sources or from a partial substitution of abatement sulfuric acid.

Compliance Data System: A data base containing compliance information and status for all emission sources in the U.S. as they relate to clean air requirements.

Consumer surplus: On the assumption that the marginal utility of money remains constant, consumers surplus represents the gain to those consumers who would be willing to pay more than the market price for a particular good.

Docket 28300: A general investigation by the Interstate Commerce Commission of the reasonableness of class rates in the U.S. (except in the mountain Pacific and transcontinental territories) that resulted in the class rates and tariffs in use today.

Energy Data System: A data base containing fuel quality and consumption data, plant design and operating data, emission regulations, compliance information, future megawatt capacities, and air quality data.

Form 67: Federal Power Commission form used to report annual steam-electric plant and water quality control data.

Frasch process: A process developed by Herman Frasch for mining underground sulfur deposits by pumping large quantities of superheated water into the formation through pipes and pumping the melted sulfur to the surface where it is either shipped or stored as a liquid or solid.

Limestone slurry scrubbing: A process for removing sulfur oxides from flue gases by scrubbing the gases in a tower with a limestone slurry. The resulting slurry of calcium sulfites, sulfates, unreacted limestone, etc., is sent to a disposal pond where the solids settle out with no further treatment.

Magnesia slurry scrubbing: A regenerative process for the removal of sulfur oxides from flue gases by scrubbing the gases in a tower with a magnesium oxide slurry. The magnesium sulfite formed in the slurry is removed and thermally decomposed into magnesium oxide and a stream of concentrated sulfur dioxide gases. The regenerated magnesium oxide is returned to the scrubbing tower and the concentrated sulfur dioxide stream is fed to a conventional contact sulfuric acid plant for the production of commercial (98%) sulfuric acid. This process is called magnesia (MgO) slurry scrubbing in the text.

Market demand: Amount of goods that buyers are ready to buy at each specified price in a given market at a given time (also called demand schedule). Demand for abatement acid in this study is simulated as though all consumption occurred at sulfuric acid plants producing at 330 days/yr.

Market supply: Amount of goods that sellers are ready to sell at each specified price in a given market at a given time (also called a supply schedule).

Supply of H_2SO_4 in this study represents either production at each of the commercial acid plants or purchases from any power plant capable of producing abatement acid or sulfur.

Mutually exclusive set number: A number used in the transportation subsystem to derive shipping costs between two points.

National Emissions Data System: A computer-based EPA emission inventory system for storing and retrieving estimates of the criteria pollutants from both point and area sources.

National Rate Basis Tariff: Tariff containing alphabetical lists of all rail stations with rate basis applicable.

Net social gain: Monetary measure of the social benefit enjoyed from recycling abatement byproduct sulfuric acid into productive use. It is the combination of consumer and producer surplus.

Optimum useful life: Identified in this study as the minimum point on the long-run average total cost curve for an acid plant. At this point the added capital cost savings enjoyed by increasing useful life one year equals the added maintenance saving from shortening useful life one year.

PEDCo-Environmental Specialists, Inc.: The company that gathers information under contract to EPA on FGD by direct interviews with and surveys of utilities in the U.S.

Producer surplus: The difference between the market price at which a producer sells and the respective lower supply prices at which he would be willing to offer lesser amounts of a particular product.

Product differentiation: Any difference, real or imaginary, between two or more very similar goods or services that may result in preference for one over the other without regard to price.

Scrubbing cost screen: Designed in the study as an economic screen to select the most efficient power plant boilers in terms of unit cost of abatement production of 100% H_2SO_4 equivalent. Equivalent 100% H_2SO_4 in any flue gas desulfurization process is the amount of 100% H_2SO_4 which could have been produced from the sulfur values in abatement byproducts, such as, calcium sulfite, calcium sulfate throwaway sludge, or elemental sulfur.

Standard Point Location Code: A transportation-oriented 6-digit number prescribed by the National Motor Freight Association under the guidance of the SPLC policy committee. It is used as a logistical linkage between all possible shipping origins and destinations for truck and/or rail.

Wellman Lord/Allied Process: A regenerative process for the removal of sulfur oxides from flue gases by scrubbing the gases in a tower with a solution of sodium sulfite. The sodium bisulfite formed is thermally decomposed (in a separate vessel) to sodium sulfite and sulfur dioxide gas. The regenerated sodium sulfite is returned to the scrubbing tower and the sulfur dioxide gas is reduced with natural gas to form molten elemental sulfur.

GENERAL CONVERSION FACTORS

EPA policy is to express all measurements in Agency documents in metric units. Values in this report are given in British units for the convenience of engineers and other scientists accustomed to using the British system. The following conversion factors may be used to provide metric equivalents.

Conversion Factors for Metric Equivalents of British Units

British			Metric	
ac	acre	0.405	hectare	ha
bbl	barrels of oil	158.97	liters	l
Btu	British thermal unit	252		
ft^3	cubic feet	0.02832	cubic meters	m^3
gal	gallons	3.785	liters	l
lb	pounds	0.4536	kilograms	kg
lb/ft^3	pounds per cubic foot	16.02	kilograms per cubic meter	kg/m^3
lb/hr	pounds per hour	0.126	grams per second	g/sec
ton	tons (short)[a]	0.90718	metric tons	t
ton, long	tons (long)[a]	1.016	metric tons	t
ton/hr	tons per hour	0.252	kilograms per second	kg/sec

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[a] All tons are expressed in short tons in this report except sulfur which is expressed in long tons.

POTENTIAL ABATEMENT PRODUCTION AND MARKETING OF BYPRODUCT SULFURIC ACID IN THE UNITED STATES

EXECUTIVE SUMMARY

INTRODUCTION

Emission control regulations for the electric power industry require utilities to either burn fuel with a low enough sulfur (S) content to meet the standard or to remove a portion of the S before, during, or after combustion. Coal is the predominant fuel for power boilers and its use will increase. Utilities generally prefer use of complying coal when it is the economic choice compared to other alternatives for control. However, complying fuel is not always available near the areas of high electricity demand. Technology for removal of S from coal prior to or during combustion is being developed but will not make a substantial contribution to control in the next decade. The primary alternative to use of fuel that meets the emission requirement is removing sulfur oxides (SO_x) from the flue gas produced when the coal is burned in the boiler. Use of flue gas desulfurization (FGD) technology currently accounts for only a minor portion of the control required, but its use is growing as a result of limited alternatives to meet compliance schedules. Most applications are based on lime and limestone scrubbing. These methods produce high volumes of waste solids for utilization or ultimate disposal. Technology for recovery of S in useful form is being developed that will provide an alternative to production of waste solids. Recovery of S from flue gas would conserve natural S reserves and reduce the requirement for energy used in mining S. One of the major uncertainties associated with this approach is the marketability of recovered S byproducts.

In this study sponsored by the U.S. Environmental Protection Agency (EPA), the Tennessee Valley Authority (TVA) has evaluated the potential markets for S and sulfuric acid (H_2SO_4) that could be economically produced by the power industry as compared to use of clean fuel or limestone scrubbing. A market simulation model was developed to evaluate distribution of byproducts from smelters as well as power plants in competition with the existing markets based on an assumed S price of $60/long ton in 1978. This value of S is representative of projected costs of production. Recovery of S from gas and oil was not included in the study although delivered price of S reflects this competition.

CONCLUSIONS

A greater portion of future supply of S will have to come from other than natural sources. Beyond the year 2000, the demand will exceed the supply of natural S (1). Recovery of S byproducts from coal combustion could make a substantial contribution to the additional supply.

The entire U.S. electric utility industry was characterized from Federal Power Commission (FPC) data (2) with respect to plant age, fuel type, capacity, load factors, and SO_x emission rates for the operating year 1978. Out of a total of 3382 boilers located at 800 power stations, 833 boilers at 187 stations were projected to be out of compliance with current applicable emission regulations. The total SO_x emissions from these 187 plants are equivalent to 17.5 Mtons (M = 1 million) of H_2SO_4; total H_2SO_4 consumption in the U.S. was estimated to be 32.2 Mtons in 1978. Therefore the total market is about twice the potential byproduct production.

For the plants estimated to be out of compliance, limestone scrubbing is generally the least-cost scrubbing method when credit for byproduct sales is not included but when credit is applied, production of byproducts becomes competitive; of the alternatives considered in this study, production of H_2SO_4 was less expensive than production of S. An alternative to use of scrubbing was provided by comparing the cost of scrubbing with selected values of premium cost of complying fuel. The values were selected to determine the effect on potential volume of abatement products.

When the clean fuel premium was set at $0.70/MBtu, the mix of least-cost compliance methods was:

Purchase complying fuel	71 plants
Use limestone scrubbing	87 plants
Produce byproduct acid	29 plants

The amount of acid produced and marketed totaled approximately 6 Mtons; an additional 5 Mtons could have been produced at a lower cost than the alternative compliance method selected but could not be sold in competition with acid produced from elemental S priced at $60/ton. The simulation model was designed to allow the nonferrous smelter industry to compete with the utility industry for byproduct markets. The total byproduct acid supplied from both industries was 7.11 Mtons or 22% of the total H_2SO_4 market; however, some of the plants that are good candidates for recovery may be implementing other compliance plans. The control of sulfur dioxide (SO_2) emissions in the utility industry through use of recovery technology could contribute 56% of the estimated total reduction needed for the industry to be in compliance. Further use of recovery technology will depend primarily on substantial increases in elemental S prices which are difficult to predict. Reduction in the cost of control technology would also increase the potential for increased production of byproducts, but the costs are not likely to improve significantly. Reduction in transportation costs is a more realistic possibility for improving economics of marketing byproduct acid. Higher levels of clean fuel premium would not affect the results since the acid supply at the maximum value studied exceeded the demand.

The development of data bases and programs for use of the model to predict byproduct market potential resulted in capability to perform other highly relevant calculations.

The scrubber cost generator may be used to estimate the investment and operating costs of alternative scrubbing systems for all existing and planned power plants. In this study, costs were estimated for limestone, magnesium oxide (MgO), and Wellman-Lord/Allied scrubbing systems for all plants projected to be out of compliance in 1978. For use in the study, relativity of costs was the primary interest. However, the input cost data could be refined to reflect special design considerations for specific plants to improve the accuracy of estimates for planning and analyses.

The procedure for evaluating compliance status based on applicable standards and FPC projection of fuel characteristics will be useful in estimating the effect of changing emission standards on the cost of compliance. The study reported here was based on the State Implementation Plans (SIP) regulations that were in effect as of June 1976.

The transportation model that was developed to distribute byproduct acid from supply points to areas of use is a sophisticated program that has potential for extensive use. The model calculates actual, rate-base mileage between any two points on the established railway network. For this study, tariffs were incorporated for H_2SO_4 movements. Available tariffs for any other commodity could be incorporated to calculate actual transportation costs between any two points.

An important finding was that while long-run competitive equilibrium solutions predict what may happen in competitive markets they do not identify net social gain. The savings to both industries at the \$0.70/MBtu clean fuel premium run resulting from absorption of abatement byproduct acid in the existing market amounted to \$122,877,000 or \$16.20/ton of acid utilized.

METHODOLOGY

The objective of the overall marketing model is to simulate long-run competitive equilibrium market conditions for S and H_2SO_4 in the U.S. as might be impacted by production of abatement acid or S. To simulate these conditions, the cost to both the H_2SO_4 and the power plant industries is minimized subject to the condition that acid demand is met either from traditional S sources or from substitution of abatement H_2SO_4.

Analysis of the model addresses three choices for the steam plants that are not meeting the current SIP standards. These include (1) selecting a clean fuel strategy, (2) selecting a limestone-throwaway scrubbing technology, or (3) selecting an H_2SO_4 (MgO)- or S- (Wellman-Lord/Allied) producing scrubbing technology. Costs for production of S by the Wellman-Lord/Allied process were higher in all cases studied than production of H_2SO_4. Projected savings in distribution costs for S compared to H_2SO_4 did not offset the incremental production costs. Costs for use of the Wellman-Lord/Allied technology will be more clearly defined during the current full-scale demonstration, partially funded by EPA, at the Mitchell Station of the Northern Indiana Public Service Company. Revised information will be included in the model. The incentive for production of S is high because it is a safe, noncorrosive, convenient material to handle, and can be easily stockpiled for long periods of time at relatively low cost. Moreover, fluctuations in market demand could be met with less impact to both the producer and consumer. It is likely that a mix of marketable byproducts will ultimately provide the least-cost compliance with SO_2 regulations in the utility industry. Technology for production of S should be fully developed so that the choice is available and so that accurate information is available for cost comparisons with other methods of control.

The optimal solution predicts not only which acid producer would buy and which steam plant would sell H_2SO_4, but also which steam plant would sell to which acid plants. Any variations to this optimal solution would increase the total cost to both industries.

A flow diagram of the major system design requirements is outlined in Figure S-1. The major data bases feed the market simulation model through cost generation models as follows:

1. Emission control requirements for SO_x were determined for each power plant boiler, stack, or plant projected to operate in 1978 using the FPC data (Form 67), June 1976 SIP, and New Source Performance Standards (NSPS).

2. The scrubbing cost generator was developed to provide unit production costs for byproduct H_2SO_4, elemental S, and limestone-throwaway sludge including potential production quantities for each power plant boiler. It was designed as an economic screen to select the most efficient boiler combinations for meeting compliance on the basis of cents/MBtu heat input for each scrubbing system considered. The results of this screen provide the lowest cost method for compliance with given scrubbing technology. This information is fed to the market simulation model to identify both the relative efficiency as well as unique location advantages for all power plant boilers producing abatement acid in competition with byproduct smelter acid producers in the existing market. The marketing model then estimates long-run competitive equilibrium solutions based on realistic outputs of abatement byproducts by identifying major candidates for abatement byproduct production and consumption versus a limestone-throwaway strategy and/or the alternative of using a clean fuel.

3. The acid production cost generator encompasses the elemental S producers, the S-burning H_2SO_4 producers, and the byproduct H_2SO_4 producers associated with smelter operations. These data bases were developed from the TVA computerized data base on worldwide manufacturers of fertilizer and related products. This information supplemented by references from other sources provided the necessary inputs to the acid production cost generator to provide unit avoidable production costs for each H_2SO_4 plant projected to operate in 1978.

4. Transportation and distribution options were calculated by the transportation cost generator for H_2SO_4 and elemental S for all possible transfer combinations between the S producers, the electric utilities, smelter plants, and H_2SO_4 plants considered in this study.

Compliance Test

The SO_2 emission and compliance model uses the projected annual fuel consumption and characteristics data to calculate the annual quantity of S that is emitted from each boiler and plant. For each plant, allowable emissions are calculated based on NSPS for new boilers or the applicable SIP for existing boilers taking into account heating value and S content of the

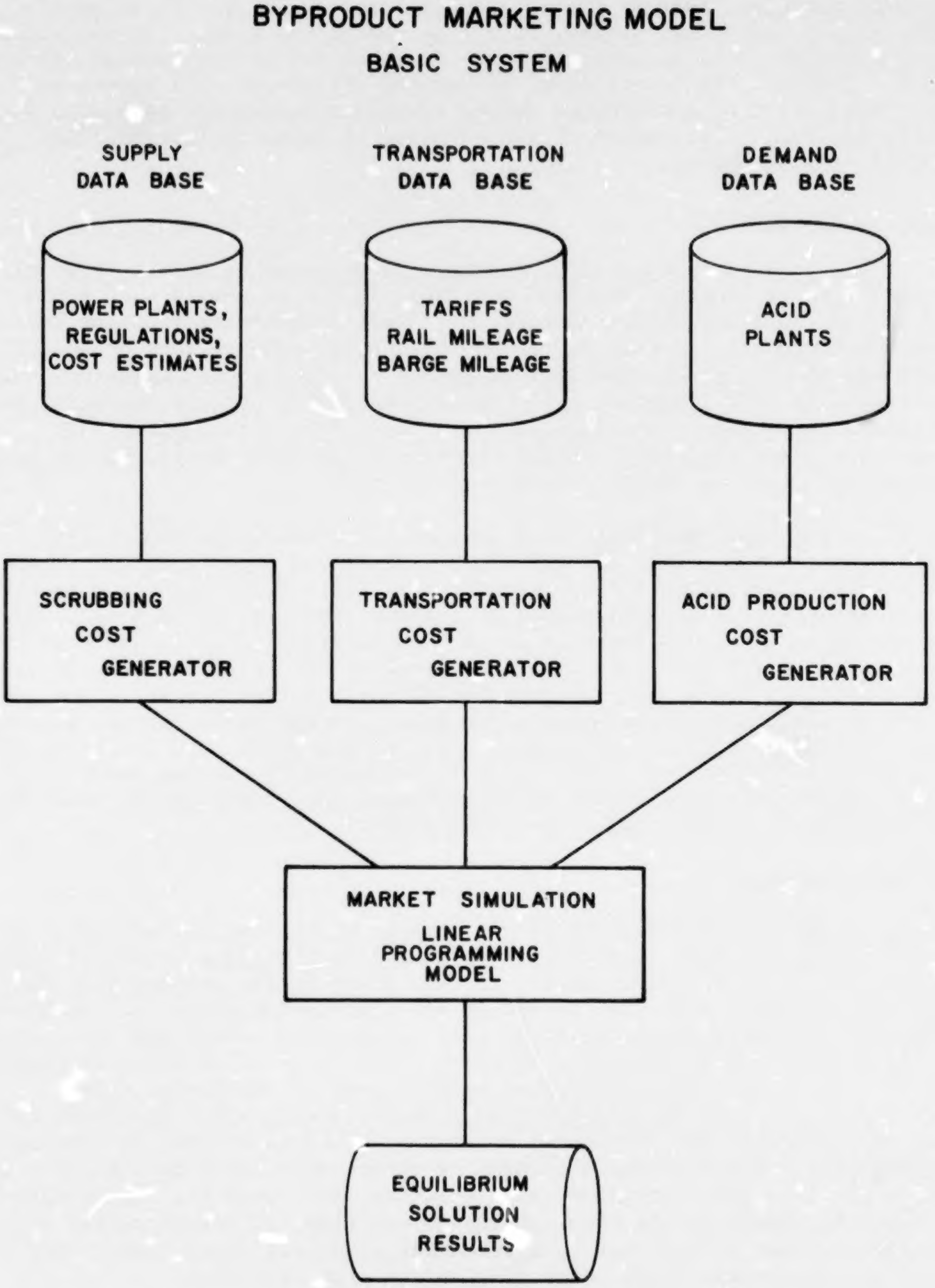
BYPRODUCT MARKETING MODEL
BASIC SYSTEM
SUPPLY DATA BASE
TRANSPORTATION DATA BASE
DEMAND DATA BASE
POWER PLANTS, REGULATIONS, COST ESTIMATES
TARIFFS RAIL MILEAGE BARGE MILEAGE
ACID PLANTS
SCRUBBING COST GENERATOR
TRANSPORTATION COST GENERATOR
ACID PRODUCTION COST GENERATOR
MARKET SIMULATION LINEAR PROGRAMMING MODEL
EQUILIBRIUM SOLUTION RESULTS

Figure S-1. Flow diagram for major system design requirements.

fuel. Excess emissions expressed as tons of S which must be removed are estimated as the difference between the calculated actual and allowable values. The compliance test selects the applicable level of SIP as (1) an entire plant, (2) an individual boiler, or (3) an individual stack. In all cases where scrubbers could be used, they are designed for an SO_2 removal efficiency of 90%. However, the actual level of removal efficiency will depend on better definition of performance during sustained full-scale operation when coal is the fuel. The amount of gas scrubbed is based on increments of standard-size scrubbers.

Scrubber Cost Generator

In all cases the SO_2 control strategy is selected on the basis of minimum cost for compliance. The data generated in the scrubbing cost model are used to calculate the scrubbing cost of a limestone-throwaway system versus a salable byproduct for each of the 833 boilers or combinations of boilers identified in this study that will be out of compliance with emission control regulations in 1978 (based on 1976 regulations). The cost is expressed as cents/MBtu for direct comparison with the clean fuel alternative. The alternative clean fuel level (ACFL) represents the premium that can be paid for complying fuel in lieu of using an FGD system.

The model also calculates cost differential between scrubbing with a limestone-throwaway system and scrubbing with MgO to produce H_2SO_4. This accommodates identifying the incremental cost difference of the two systems for all boilers or the combinations of boilers included in the model. This incremental cost becomes input to the marketing model which is designed to determine potential for production and marketing of abatement H_2SO_4 at various power plant locations. The comparative FGD costs for each power plant considered in the study can be used to generate a supply curve for the production of abatement H_2SO_4. The supply curve for abatement acid is presented graphically in Figure S-2. This curve is estimated by ranking power plant boiler combinations from lowest to highest cost for producing abatement H_2SO_4 as a function of accumulated supply quantities.

Acid Cost Generator

H_2SO_4 plants are widely scattered throughout the industrial sector of the U.S.; acid has been traditionally produced by S-burning plants in captive use near the point of consumption. In this study it was assumed that the H_2SO_4 market can be simulated as though all consumption occurs at the H_2SO_4 plants and that acid-producing firms will close these plants and buy abatement acid if it can be delivered at costs equal to or below their avoidable cost of production. This assumption ignores some of the market entry barriers but provides the basis for an economic assessment. Avoidable cost is an estimation of the production costs that could be avoided by closing an existing acid plant assuming abatement byproduct acid would be available in amounts equal to the plant production capacity (330 days/yr). To develop the required inputs to the model on the demand side, it was necessary to identify the acid plants that burn elemental S for the production of H_2SO_4 and calculate the avoidable costs of production at each plant.

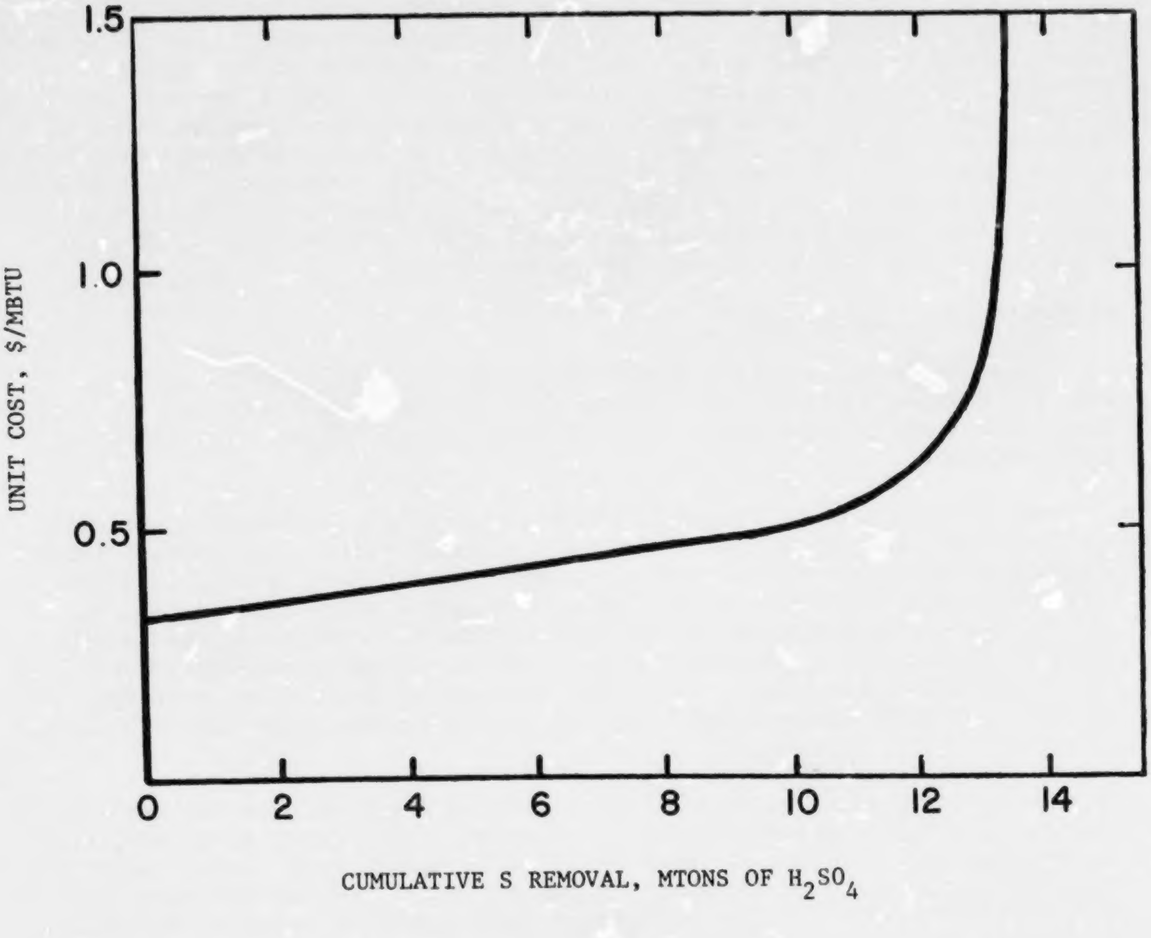

Figure S-2. The supply cost curve for abatement acid.

The avoidable costs (theoretical) were calculated at each of the 90 acid plant locations considered in the study. Costs of manufacture based on data generated indicated that most of the acid production costs range from \$25.00-\$45.00 depending on plant location, size, and age; the March 1976 price for H_2SO_4 (100% H_2SO_4 f.o.b.) was \$44.95/ton. A summation of capacity of acid plants versus avoidable cost of production is shown in Figure S-3. The resulting plot defines the demand curve for abatement acid. The demand curve is estimated by ranking all acid plants from highest to lowest cost and accumulating demand quantities to show acid cost as a function of acid plant capacity. At a very high cost of alternative supply, only a few acid producers could justify buying rather than producing H_2SO_4. As supply cost of abatement acid declines, more acid producers would become potential customers. At low supply costs all but the largest, most modern acid plants located near S supplies could be shut down. The important implication for the present study is that small quantities of abatement acid could be marketed at high value but as the supply increases the value declines.

Transportation Cost Generator

To assess representative competitive costs, a market system analysis must generate accurate S freight rates from the Frasch S sources to the acid plants and H_2SO_4 freight rates from all power plants and/or smelters to all H_2SO_4 plants.

The linkage used in the study between the S-H_2SO_4 and power plant data bases and the rate generation system is a Standard Point Location Code (SPLC). A flow diagram of the freight rate generation system used in this model is shown in Figure S-4. This shows that an SPLC for a power plant origin and one for H_2SO_4 plant destination are input to the National Rate Base Tariff (NRBT). This tariff determines for rail rate purposes the basing points for the origin and destination. Output are two sets of codes used to define mileage and tariff rates between the byproduct shipping origin and destination points.

It is important to identify not only the mileage but also the tariff number. A slight error in mileage is not nearly as critical as knowing which tariff applies. Four tariffs were found in published H_2SO_4 rates. Rates for eight other tariffs were generated by the TVA Navigation and Regional Economics Branch (Division of Navigation Development and Regional Studies) from these using sound traffic legal arguments similar to the negotiation process that would ensue should large acid movements become a reality.

RESULTS OF ANALYSES

S and H_2SO_4 Industry

The U.S. Bureau of Mines (BOM) (3) reports the production of S in all forms in 1976 at 10.9 Mlong tons. Elemental S was produced by 69 companies at 182 plants in 32 states with 10 of the largest companies owning 57 plants and accounting for 75% of the output. The production was concentrated in Texas and Louisiana accounting for 68% of the total output. The Frasch S was produced in these two states at 12 mines, 5 of the largest mines accounting

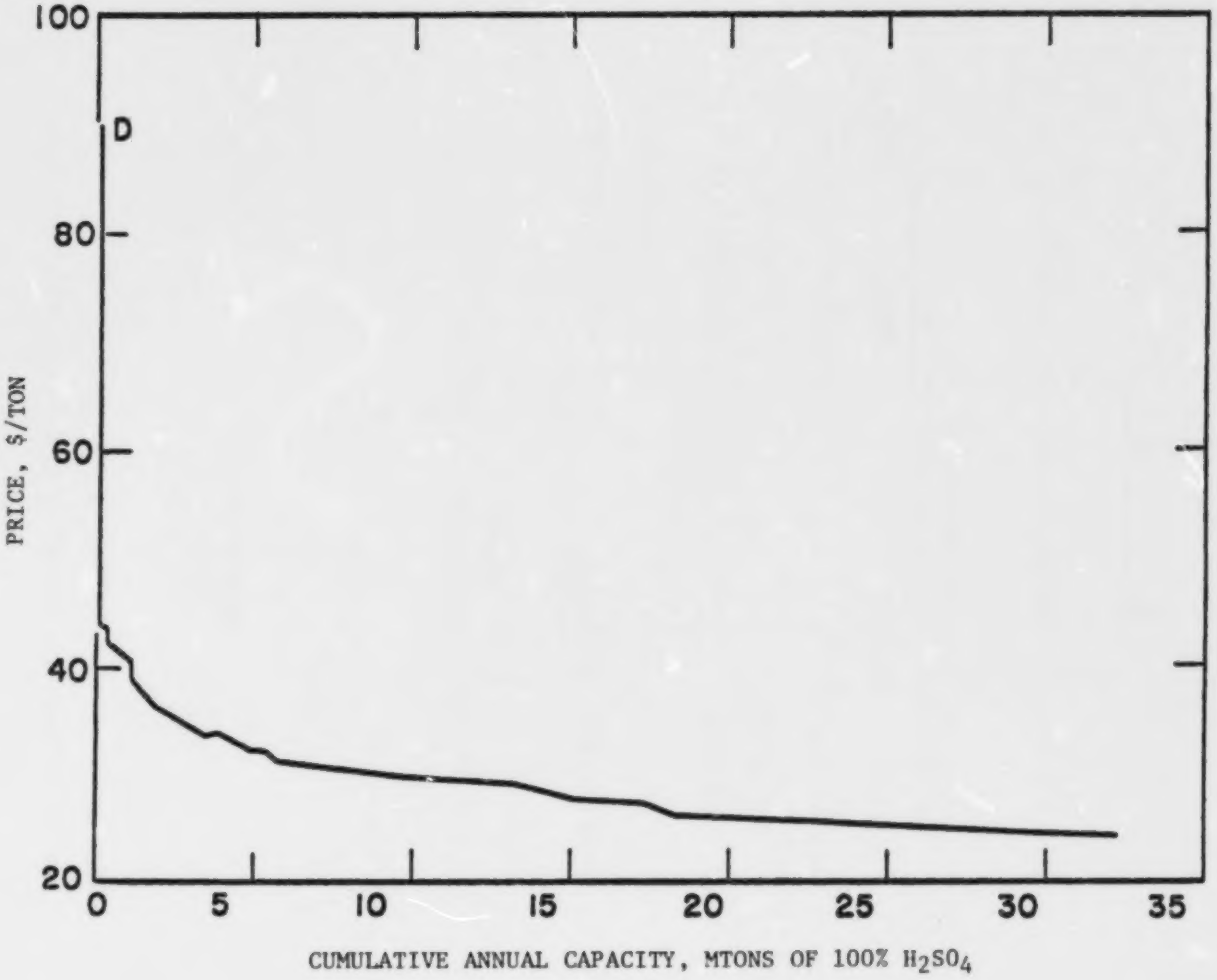

Figure S-3. Abatement byproduct H_2SO_4 demand curve (Eastern States).

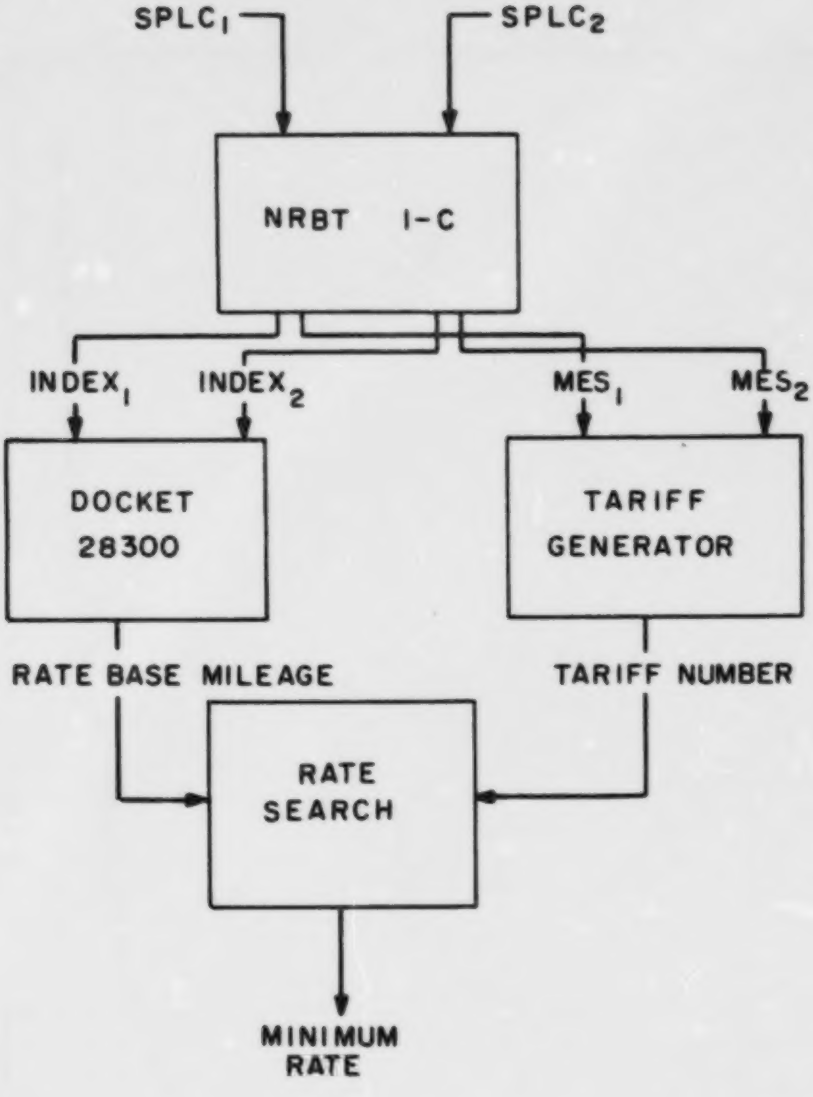
SPLC1
SPLC2
NRBT I-C
INDEX1
INDEX2
MES1
MES2
DOCKET 28300
TARIFF GENERATOR
RATE BASE MILEAGE
TARIFF NUMBER
RATE SEARCH
MINIMUM RATE

Figure S-4. Flow diagram of freight rate generation model.

for 82% of the total Frasch output and 48% of the total production of S in all forms. Long-range prediction of S demand in millions of tons is shown below.

	Forecast			
	1976	1980	1985	1990
Fertilizer	6.4	7.5	9.3	11.0
Industrial	4.5	5.3	6.0	6.8
Total	10.9	12.8	15.3	17.8

Frasch S production is a mining operation. Wells are sunk into S-bearing strata, S is melted by hot water injected into the strata, and the molten S is pumped out. The molten S is pumped from the well to either heated tanks for storage as a liquid or to vats where it cools and solidifies. About 75% of the total mining costs of Frasch S is variable, such as the cost of natural gas to heat water, water treatment, labor, and operating supplies. The cost of hot water to melt the S is by far the most important cost and will differ drastically from mine to mine as water requirements and fuel cost differ. In an analysis prepared for this study the cost of natural gas was varied from \$0.20-\$3.00/kft^3 (k = 1 thousand) with an intermediate value of \$1.00/kft^3. Water requirements or water rate varied from 1600 gal/ton of S produced to 9000 gal/ton of S. The results of this study indicated that the lowest capital investment and operating costs are associated with mines having low water rates and that cost increases markedly with increasing natural gas costs. For operation where the major variables are constant, i.e., water rate and natural gas cost, the usual economies of size prevail.

Most of the S consumed in the U.S. is used to produce H_2SO_4. Over two-thirds of the H_2SO_4 is used in the manufacture of fertilizers. A breakdown of the estimated consumption of S in all forms by end use is presented in Table S-1.

Characteristics of Power Plants

In 1973 utilities were requested by FPC to project fuel consumption and characteristics for 1978. The majority of utilities provided FPC with these projections. For the utilities which did not project this information, fuel consumption and characteristics reported for 1973 were used. Based on the updated projections, Table S-2 shows the consumption rates and characteristics of fossil fuels projected to be utilized during 1978. For plants which use multiple fuels and did not project their 1978 consumption, a method for projecting distribution of fuel type was developed.

A comparison of the total projected 1978 coal, fuel oil, and gas consumption with the historical 1973 fuel consumption by region is shown in Table S-3. The projections indicate a general increase in the consumption of coal and oil, but a slight decrease in the consumption of gas. The regional increases or decreases are primarily influenced by fuel availability and price. In reviewing the data, it must be remembered that a significant

TABLE S-1. U.S. CONSUMPTION OF S IN ALL FORMS BY END USE

(klong tons S equiv)

	1974	1975	1976
H_2SO_4			
Fertilizer acid			
H_3PO_4	4,945	5,410	5,560
Normal superphosphates	405	290	230
$(NH_4)_2SO_4$ and other	685	670	610
Total fertilizer acid	6,035	6,370	6,400
Industrial acid	3,715	3,080	3,285
Total H_2SO_4	9,750	9,450	9,685
Non-acid	1,250	1,200	1,215
Total in all forms	11,000	10,650	10,900

TABLE S-2. PROJECTED 1978 FOSSIL FUEL CONSUMPTION RATES AND CHARACTERISTICS

	All plants	Plants out of compliance
Coal		
Total consumption		
ktons[a]	475,600	226,800
GBtu[b]	10,408,300	5,125,000
Heating value, Btu/lb	10,943	11,300
S content, % by wt	2.12	2.81
Equivalent SO_2 content, lb SO_2/MBtu[c]	3.87	4.97
Oil		
Total consumption		
kbbl	620,200	110,200
GBtu	3,827,400	686,900
Heating value, Btu/gal	146,924	148,454
S content	0.99	1.42
Equivalent SO_2 content, lb SO_2/MBtu	1.08	1.54
Gas		
Total consumption		
Mft^3	2,556,000	108,200
GBtu	2,602,200	117,000
Heating value, Btu/ft^3	1,018	1,081

a. k = one thousand.
b. G = one billion.
c. M = one million.

TABLE S-3. COMPARISON OF PROJECTED 1978 REGIONAL FOSSIL FUEL CONSUMPTION WITH HISTORICAL 1973 CONSUMPTION

Geographic region[a]	Coal, ktons	Oil, kbbl	Gas, Mft^3
Historical 1973 consumption			
New England	1,080	82,930	6,070
Middle Atlantic	46,990	144,690	64,730
East North Central	135,960	23,340	105,590
West North Central	31,620	3,440	352,820
South Atlantic	75,860	141,380	202,660
East South Central	63,060	6,510	73,750
West South Central	4,730	20,850	1,957,070
Mountain	23,930	8,990	207,630
Pacific	3,740	76,970	451,220
U.S. total	386,970	509,100	3,421,540
Projected 1978 consumption[b]			
U.S. total	475,570	620,250	2,556,020

[a] The states included in each geographic region are: New England - Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont; Middle Atlantic - New Jersey, New York, Pennsylvania; East North Central - Illinois, Indiana, Michigan, Ohio, Wisconsin; West North Central - Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota; South Atlantic - Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia; East South Central - Alabama, Kentucky, Mississippi, Tennessee; West South Central - Arkansas, Louisiana, Oklahoma, Texas; Mountain - Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming; Pacific - California, Oregon, Washington.

[b] Regional consumption data not available.

amount of new generating capacity between 1973 and 1978 is from nuclear units. The data shown include the effect of projected decreases in fossil fuel utilization as a result of new nuclear units coming online as well as changes in fossil fuel consumption resulting from decreases in fuel availability of increases in cost.

The operating characteristics of all 800 U.S. power plants projected to be in operation in 1978 are outlined in Table S-4. Also included in this table are the characteristics of the plants projected to operate out of compliance in 1978. As the data in the table indicate, 187 power plants out of a total of 800 were calculated to be out of compliance. It should be noted that many of the plants estimated to be out of compliance are likely implementing compliance plans that are different from those selected for this study. Even though plants out of compliance make up only 32% of the total population with respect to capacity, they burn about 50% of the total coal; only 20% of the total oil, and only 5% of the total gas. Plants out of compliance have a 30% higher S content in the coal burned and a 43% higher S content in the oil burned than the overall nationwide average. The average boiler size for plants out of compliance was about 30% greater than the average for all plants. The age range of boilers, the range of boiler sizes, and boiler capacity factor for plants out of compliance were not significantly different from the industrywide values.

Byproduct Acid from Smelters

The 14 smelters located in the 11 Western States were analyzed separately from the 14 smelters in the 37 Eastern States of the U.S. The model assumes that existing S-burning acid plants and byproduct acid plants associated with smelter operations were operating at an equilibrium position in the 1975 market year. The model then addresses the incremental acid that is projected to be produced at both existing and new smelter locations in 1978. The 1978 incremental production estimated for the Western States amounted to 849,000 tons of acid. The analysis for smelters located in the Eastern States amounted to 811,000 tons of acid.

Part of the acid produced by western smelters was distributed in the East. This surplus western acid was marketed in the simulation model through transshipment terminals supplied by unit trains. The terminal locations included Chicago, Illinois; St. Louis, Missouri; Memphis, Tennessee; Baton Rouge, Louisiana; and Houston, Texas. Two additional transshipment terminals were added in the model at Buffalo, New York, and Detroit, Michigan, in order to analyze the marketing of 200,000 tons of byproduct acid from smelters in Canada. This concept is presented graphically in Figure S-5.

Byproduct Acid from Power Plants

The clean fuel alternative is defined as the incremental additional price for fuel that will meet the applicable SO_2 emission regulation. The ACFL selected for the model runs ($0.00, $0.35, $0.50, and $0.70/MBtu) were chosen to show the effect on potential volume of abatement acid. For some power plants with multiple boiler installations a mix of alternative methods

TABLE S-4. POWER PLANT OPERATING CHARACTERISTICS PROJECTED FOR 1978

	1978 all U.S. plants	1978 plants out of compliance
No. of power plants	800	187
No. of boilers	3,382	833
Total capacity, MW	411,000	132,600
Total fuel		
Coal, ktons	475,600	226,800
Coal, GBtu	10,408,300	5,125,100
Oil, kbbl	620,300	110,200
Oil, GBtu	3,827,400	686,900
Gas, Mft^3	2,556,000	108,200
Gas, GBtu	2,602,200	167,000
Average S content of coal, %	2.12	2.81
Average S content of oil, %	0.99	1.42
Emissions, equivalent tons H_2SO_4		
Total emitted	29,552,100	17,562,300
Required abatement	9,912,600	9,912,600
Average capacity factor, %	31.87	35.12
Average boiler generating capacity, MW	122	159
Age of boilers, %		
0-5	5	10
6-10	8	10
11-15	8	6
16-30	42	42
>30	37	32
Size of boilers, %		
<200	82	75
200-500	11.7	15
501-1000	6	9
>1000	0.3	1
Capacity factor of boilers, %		
<20	40	35
20-40	20	17
41-60	23	29
>60	17	19

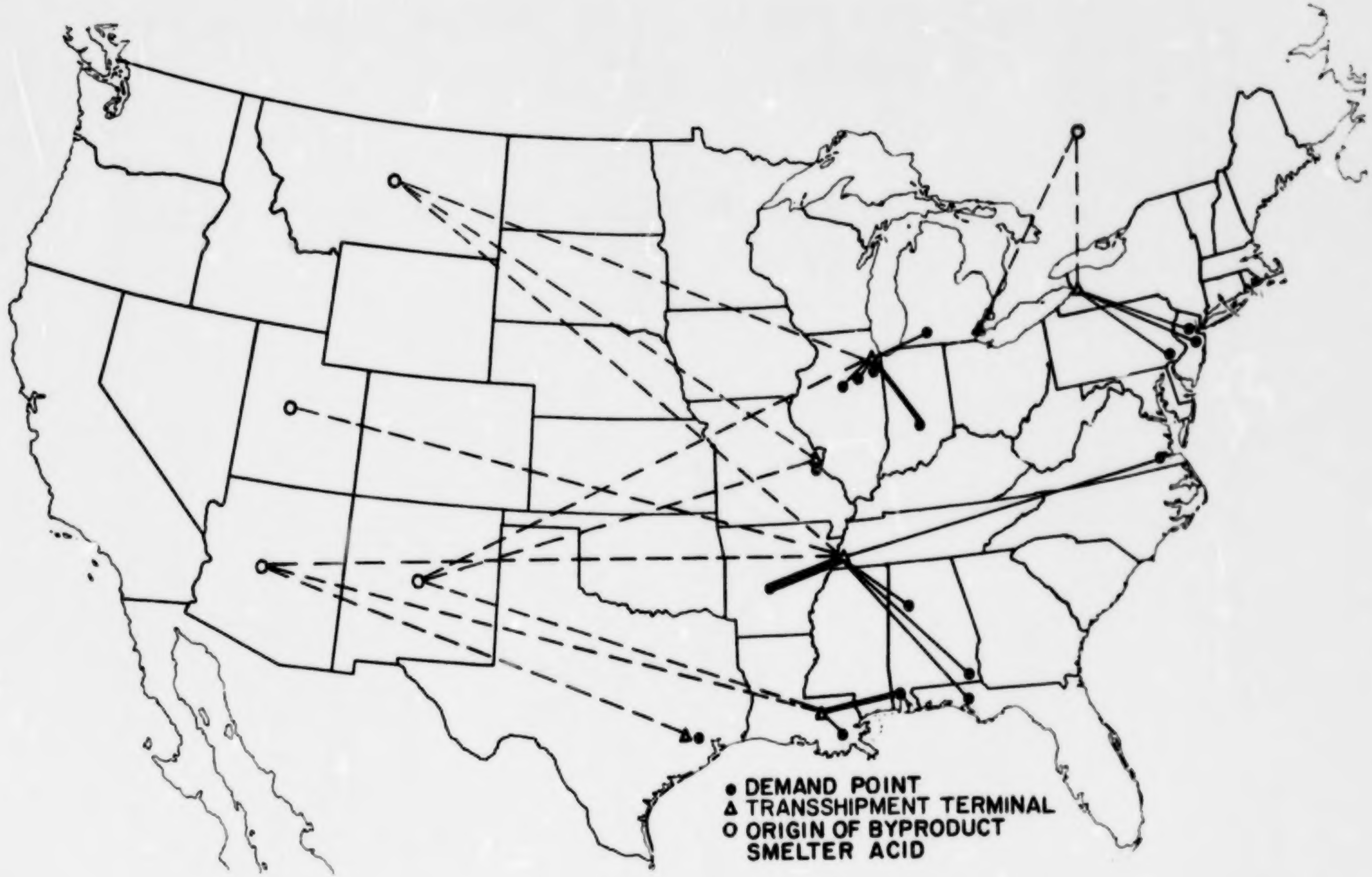
● DEMAND POINT
Δ TRANSSHIPMENT TERMINAL
○ ORIGIN OF BYPRODUCT SMELTER ACID

Figure S-5. Geographic distribution of assumed supply and demand for western and Canadian acid in zero ACFL model run.

produce the least-cost compliance strategy. A summary of the distribution of compliance strategies selected by the model for each ACFL model run is listed as follows:

	ACFL, cents/MBtu			
Compliance strategy	0	35	50	70
Plants using clean fuel only	187	168	113	71
Plants using only limestone scrubbing	0	7	41	77
Plants using limestone scrubbers and clean fuel	0	4	7	10
Plants using MgO scrubbing only	0	8	24	29
Plants using MgO scrubbing and clean fuel	0	0	2	0
Total power plants	187	187	187	187

The potential production and marketing of abatement acid for power plants that produced acid in each of the model runs are outlined as follows:

	ACFL, cents/MBtu			
	0	35	50	70
No. of plants	0	8	26	29
Thousands of tons marketed	0	2,554	5,108	5,595

Power plants that were the best candidates for production of byproduct acid were generally larger, newer plants with high load factors. The distinctive characteristics were (1) most boilers <10 yr old, (2) average size about 600 MW (<15% smaller than 200 MW), and (3) the average capacity factor about 60%. The average load factor for potential acid-producing plants was more than three times as high as the average for all plants considered.

A summary of the compliance strategies developed from the model runs for controlling excess emissions projected for 1978 is outlined in the following tabulation:

Strategies Selected for Reducing Emissions

(Reductions expressed as equiv ktons of H_2SO_4/yr)

ACFL, cents/MBtu	By using clean fuel	Total by scrubbing	By MgO scrubbing	By limestone scrubbing	Total reduction
0	9,912	0	0	0	9,912
35	7,993	2,885	2,554	330	10,878
50	3,123	9,503	5,108	4,395	12,627
70	700	12,583	5,595	6,988	13,284
∞	-	13,598	-	-	13,598

Equilibrium Solution

A summary of model results for smelter and power plant sales to acid plant demand points for all model runs is outlined in Table S-5. These results show the potential quantity of power plant acid in relation to the total market. At the $0.70/MBtu ACFL, the potential for production of acid (abatement capacity) at a cost below the alternative clean fuel premium fuel cost exceeded the market demand (sales) for the acid by 5 Mtons. The plants that would not be able to market the acid used limestone scrubbing even though production of acid would have been less costly if markets were available. At the $0.35/MBtu level, essentially all of the acid that could be produced economically compared to purchase of complying fuel was sold. The small differential in sales between the $0.50 and $0.70/MBtu level of ACFL indicates that the market for byproduct acid from power plants was nearly saturated at 5 Mtons, or approximately 15% of the total market. Further substitution of byproduct acid in the existing market would depend on substantial increase in the price of S; $60 was assumed for the study.

Distribution of Acid Markets

Distribution of acid for the 90 acid plants considered in each model run is outlined as follows:

	ACFL, cents/MBtu			
	0	35	50	70
Producing from S	58	42	30	28
Buying from smelters only	21	11	1	5
Buying from steam plants only	0	22	41	41
Producing from S and buying from smelters	11	6	2	1
Producing from S and buying from steam plants	0	2	3	2
Producing from S and buying from smelters and steam plants	0	0	0	1
Buying from smelters and steam plants	0	7	13	12
Total acid plants	90	90	90	90

Four significant factors that affect the purchase of abatement acid by current producers of H_2SO_4 in this study are listed as follows:

1. Size
2. Age
3. Compliance with clean air standards
4. Location

Abatement acid produced in the model run from the utility industry at the $0.70/MBtu clean fuel premium was distributed to 56 different demand points in 23 states. The current supply that was replaced by byproduct acid

TABLE S-5. SUMMARY OF MODEL RESULTS FOR SMELTERS AND POWER PLANT SALES TO ACID PLANT DEMAND POINTS

(ktons of H_2SO_4)

	ACFL, cents/MBtu			
	0	35	50	70
Eastern smelters				
Capacity	818	818	818	818
Sales	818	818	818	818
Demand points	15	13	12	14
Western smelters				
Capacity	738	738	738	738
Sales	738	738	594	498
Demand points	15	8	3	3
Canadian acid				
Capacity	200	200	200	200
Sales	200	200	200	200
Demand points	4	4	2	3
Total smelter acid capacity	1,756	1,756	1,756	1,756
Sales	1,756	1,756	1,612	1,516
Demand	32[a]	24[a]	16[a]	19[a]
Mixed demand points	11	13	15	13
Steam plants				
Capacity	-	2,635	8,497	10,758
Sales	-	2,554	5,108	5,595
Demand points	-	31[a]	57[a]	56[a]
Mixed demand points	-	9	16	14
Port Sulphur to H_2SO_4 plants				
Capacity	32,237	32,237	32,237	32,237
Sales	30,481	27,926	25,516	25,126
Demand points	69[a]	50[a]	35[a]	31[a]
Mixed demand points	11	8	5	4
Port Sulphur only	58	42	30	28

a. Steam plants and eastern and western smelters can supply a common demand point.

was generally from smaller, older plants remotely located from the elemental S production points on the Gulf Coast. The larger, more efficient plants generally can produce acid at costs lower than the delivered cost of abatement byproducts; however, there are exceptions. Savings in transportation cost because of location advantage can offset production cost differential.

Sensitivity Analyses

One of the key inputs in the analysis of the potential market for abatement byproduct acid is the price of elemental S. All the results of this study are based on S price of \$60/long ton f.o.b. Port Sulphur. A \$20.00 decrease in the unit price of S lowers the avoidable cost of production for H_2SO_4 at each respective acid plant by \$6.11/ton of acid produced. This price structure would reduce the quantity of both byproduct smelter acid as well as the abatement acid from power plants that can be marketed in the model.

The model assumed distribution of byproduct acid by rail shipment. Since several of the potential producers are located on navigable waterways, barge transportation could be used. As an example of possible savings on shipment costs, estimates were made for barge shipments of selected production totaling 700,000 tons. The cost differential between rail and barge transportation totaled \$725,000 or about \$1/ton of acid. This potential savings is 11% of the average transport cost. Because barge rates are normally negotiated, rates were not available for inclusion in the transportation model. An in-depth analysis will be required before realistic conclusions can be made.

RECOMMENDATION

Information on current compliance programs for existing power plants and for additional planned capacity was not available during the period of this study. The results of the work show that the potential for use of recovery technology is good and the initial follow-on work should focus on plants where compliance alternatives are still flexible. A survey of compliance plans should be carried out and the option of producing byproduct acid should be evaluated by incorporating specific information on those plants into the program data base. This evaluation would be particularly helpful in the planning process for future coal-fired power plants or for those that may be required to convert from gas or oil to coal.

POTENTIAL ABATEMENT PRODUCTION AND MARKETING OF BYPRODUCT SULFURIC ACID IN THE UNITED STATES

Final Report

INTRODUCTION

Air quality regulations require many fossil fuel-fired power plants to meet emission limitations on sulfur oxides (SO_x) formed when sulfur (S) in the fuel is burned. The current alternatives are use of low-S fuel that meets the emission regulation or use of flue gas desulfurization (FGD) technology to remove SO_x after the fuel is burned. Other technology to convert high-S fuels to clean gas or liquids is being developed but is not yet ready for use.

The electric utility industry would generally prefer use of complying fuel if it is the economic choice. However, coal supplies that meet the emission regulations are in short supply in the eastern part of the country where a major portion of the power is produced. Much of the coal in the Western States is sufficiently low in S to meet the present New Source Performance Standards (NSPS), but limitations on mining and transportation facilities reduce the potential of this fuel supply for use in the industrial East. Moreover, proposed changes to the regulations could prevent use of coal from regions outside the area of use.

FGD technology is still in the development stage, but several power companies have installed FGD systems to comply with the regulations while burning high-S fuel. Most of the processes are based on scrubbing with lime or limestone and produce sludge that must be discarded in storage ponds. This practice commits large land areas to nonproductive use. Technology for recovery of S in useful form is also under development. These processes will provide an alternative to processes producing waste solids and will allow conservation of natural S reserves. An effective method for evaluating market potential of recovered products and for identifying the most likely mix of compliance strategies is needed to provide guidance to the utility industry in selecting from alternative systems.

In order to provide perspective on the potential use of recovery technology, the U.S. Environmental Protection Agency (EPA) contracted with the Tennessee Valley Authority (TVA) to carry out a series of studies to develop a method for comparison of FGD systems to evaluate market potential for abatement products, and to characterize and identify power plants that are the most likely candidates for producing useful products.

Phase I was completed in December 1973 using the TVA power system as a single utility example of theoretical production and distribution of abatement sulfuric acid (H_2SO_4). A computerized production-transportation model was developed and although the study was hypothetical, it provided considerable insight as to the impact that abatement H_2SO_4 could have on the existing market. Results of the study were published (4).

Phase II involved a preliminary market study of the potential use of calcium sulfate ($CaSO_4$) sludge by the wallboard fabrication industry to derive cost data for comparison of throwaway alternatives. This study was conducted early in 1974 (5).

Phase III, the subject of this report, is an expansion of the Phase I study. A TVA interim report, S-469, was prepared as part of this phase to include analysis of abatement production of elemental S as well as H_2SO_4 (6). However, the cost of abating elemental S with current technology was such that it could not normally compete in the market with abatement H_2SO_4. Possibly future technology will provide a more competitive scrubbing system. The final report of Phase III addresses the potential production and marketing of abatement H_2SO_4 by the utility industry in the 48 contiguous states of the U.S. in competition with byproduct acid produced in the smelter industry.

As presently planned future work will focus on an expanded study of $CaSO_4$ sludge utilization for wallboard, potential use of abatement S byproducts in the fertilizer industry [S, H_2SO_4, $(NH_4)_2SO_4$], and will evaluate alternative strategies for optimum technology mix considering product markets [S, H_2SO_4, $(NH_4)_2SO_4$, phosphate fertilizers, wallboard, etc.], process cost differentials, and clean fuel alternatives.

OBJECTIVES OF PHASE III STUDY

The objectives for this third phase of study are outlined as follows: Using the analysis techniques, data research, and basic computer model derived for Phase I, the expanded investigation was conducted to (1) determine the quantities of byproduct H_2SO_4 or elemental S which could be produced by air pollution abatement installations at power plants, (2) define the most economical market distribution-transportation system including storage costs, (3) determine competitive costs of H_2SO_4 producers using elemental S as raw material; costs of acid plant pollution control included, (4) determine competitive costs of elemental S production, (5) predict as a function of the above the possible net sales revenue for marketing strategies covering the existing acid market, the existing elemental S market, and the growth markets for these commodities, and (6) recommend the most practical byproduct for specific power plant installations based on results of the above tasks.

The purpose of these objectives is to provide general and practical information concerning the potential for abatement byproducts in the current production, distribution, and use of S and H_2SO_4 in the U.S. Also, the computer model of Phase I was enlarged to cover the expanded power plant data base and programed to reflect pollution restrictions dictated by

State Implementation Plans (SIP) and NSPS. The model was designed for multiproduct capability and relatively easy modification as the data bases change. A further criterion is system transferability to other potential users through the use of standard computer languages, commercial time sharing, and remote batch national computer networks, although it should be noted that the system that has been built is a highly complex system of programs and data bases requiring advanced and very specialized skills.

PHASE I MODEL

The Phase I model was a traditional transportation model solved with a linear programing algorithm. Transportation costs were calculated by a rate specialist for each possible transport combination. Cost of the abatement acid at the steam plant was assumed to be zero. The solution to the model minimized the cost of marketing abatement acid as well as the average total production cost for the H_2SO_4 industry. The model assumed that the acid plant would close down and buy abatement acid if the acid could be delivered equal to or below the avoidable cost of production.

THE EXPANDED MODEL

The 1972 Federal Power Commission (FPC) Form 67 data file contained information that could be correlated with variables used in the detailed cost estimates of the five leading FGD processes prepared by TVA in January 1975 (EPA 600/2-75-006) (7). The availability of these data provided the basis for development of a cost screen designed to identify the most promising power plant boiler candidates for abatement byproduct production. The 1973 FPC Form 67 data available in 1976, contained 5- and 10-yr projections of proposed new power plant installations. SIP and NSPS standards for air pollution control effective in June 1976 identified allowable emissions for each power plant in the U.S. A rail transportation rate generation model developed by TVA was modified to calculate accurate transportation rates for elemental S and H_2SO_4 for all origins and destinations in the rail rate territories located east of the transcontinental territory.

A systems model was designed to combine data inputs needed to assess the nationwide market potential of abatement byproducts. Three major data bases--(1) H_2SO_4 producers, (2) transportation-distribution options, and (3) power plant data (FPC, SIP, and TVA cost estimates)--supply information to feed a market simulation model through three cost generation models. All data were projected to 1978 values. The three cost generation models include (1) the transportation cost generator, (2) the scrubbing cost generator, and (3) the H_2SO_4 production cost generator. The transportation cost generator provides transportation, distribution, and storage options to calculate least-cost shipping modes considering rail, barge, or truck combinations for S-H_2SO_4 from Port Sulphur, Louisiana, to all acid plants and between all combinations of power plants, smelters, and acid plants considered in the study. The second model, the scrubbing cost generator, was designed to provide a method for projecting comparative costs for installing FGD systems on power plants projected to be out of compliance in 1978. It is used as an economic screen to select the most efficient boilers in terms of unit cost of abatement production. The third model is used to calculate the avoidable cost of production for each S-burning H_2SO_4 plant included in the study. Avoidable cost is an estimation of the production cost that could be avoided by closing an existing acid plant with the assumption that abatement byproduct acid would be available in amounts equal to the plant production capacity (330 days/yr).

Analysis of the model addresses three choices for the steam plants that are projected to operate out of compliance in 1978. This includes (1) selecting a clean fuel strategy, (2) selecting a limestone-throwaway scrubbing technology, or (3) selecting an H_2SO_4-producing scrubbing technology.

Concepts include the consideration of nonferrous smelters byproduct acid in the final solution; central regeneration facilities for one or more boiler combinations of scrubbing at power plant sites for recovery processes; the estimated cost of limestone delivered to each potential power plant scrubbing site (this required development of data for all limestone sources in the U.S.); actual emission regulation codes and values; limiting the potential acid market to users of elemental S; distinguishing between scrubbing cost estimates for new plants versus retrofitting old plants; site specific location adjustments; the addition of western power plants, acid plants, and smelters; and addition of geographic data required by the transportation system in the market simulation model. The new data sources considered in addition to the previous phase include EPA Energy Data Systems (EDS), Compliance Data Systems (CDS), the monthly report from PEDCo-Environmental Specialists, Inc., Stanford Research Institute (SRI), U.S. Bureau of Mines (BOM), National Emission Data Systems (NEDS), Centre Mark Company (CENTRE) geographic and transportation data, and several FPC publications and reports.

The expanded model allows for significantly better estimates of long-run competitive equilibrium solutions since they are based upon more realistic economic premises and outputs of abatement byproducts than the Phase I work.

A basic flow diagram of major system design requirements is shown in Figure 1. A more detailed flow diagram of the model is presented in Appendix A. It is assumed that the H_2SO_4 market can be simulated as though all consumption occurred at H_2SO_4 plants, and that acid-producing firms would close these plants and buy abatement acid if acid prices were below their projected long-run H_2SO_4 production cost. Long-run competitive equilibrium market conditions can be simulated by minimizing the cost to both the H_2SO_4 and power industries. Power plants are assumed free to produce or not to produce S or H_2SO_4 and to sell to any H_2SO_4 plant in competition with other power plants. Likewise, H_2SO_4 plants are assumed free to continue buying S from traditional sources or from power plants, and free to buy acid in lieu of production subject to competition in their respective industries. Product differentiation is not assumed significant. Problems of stable, guaranteed abatement supplies are ignored, but probably are solvable. Rail transportation

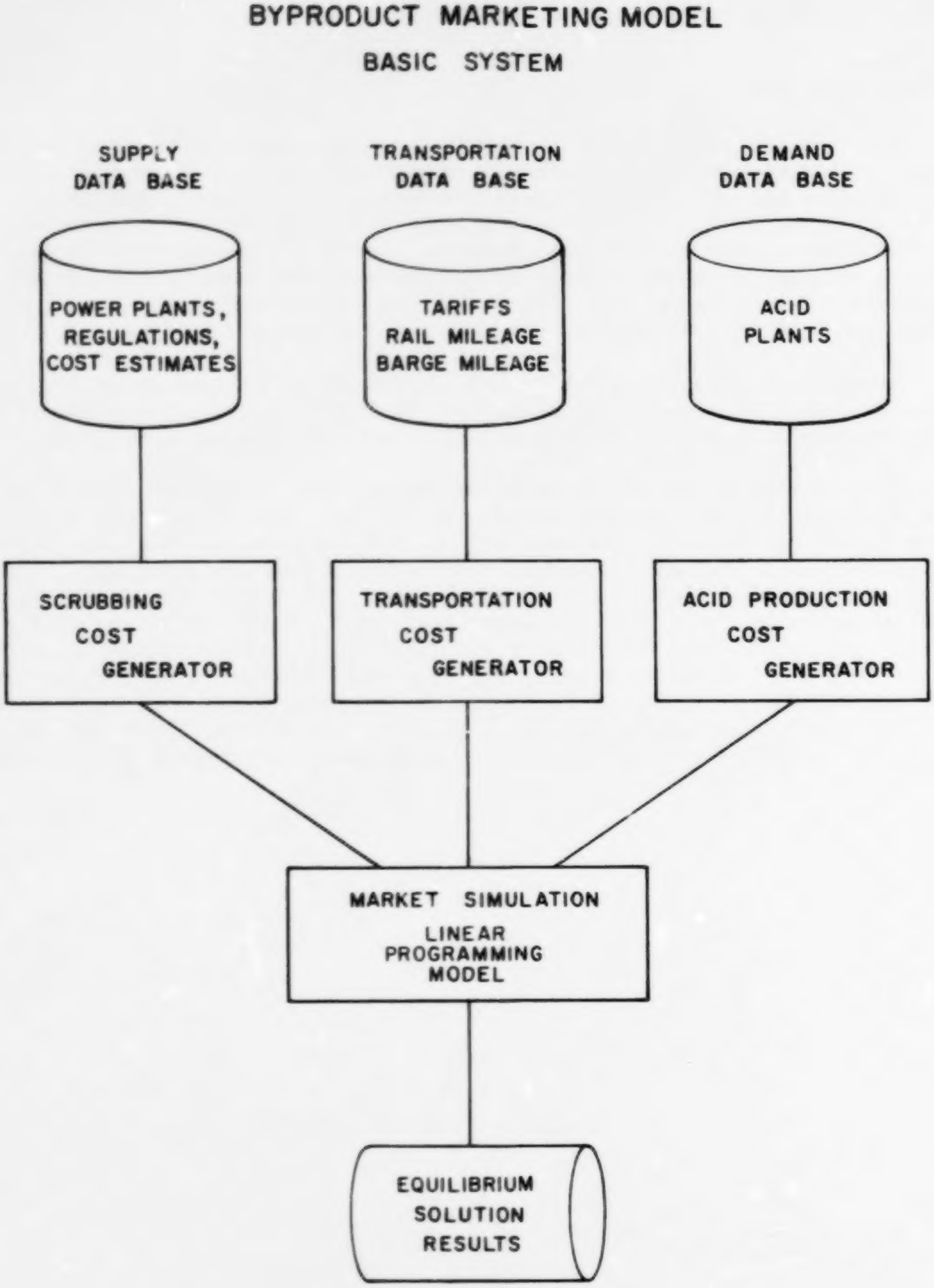
BYPRODUCT MARKETING MODEL
BASIC SYSTEM
SUPPLY DATA BASE
TRANSPORTATION DATA BASE
DEMAND DATA BASE
POWER PLANTS, REGULATIONS, COST ESTIMATES
TARIFFS RAIL MILEAGE BARGE MILEAGE
ACID PLANTS
SCRUBBING COST GENERATOR
TRANSPORTATION COST GENERATOR
ACID PRODUCTION COST GENERATOR
MARKET SIMULATION LINEAR PROGRAMMING MODEL
EQUILIBRIUM SOLUTION RESULTS

Figure 1. Flow diagram for major system design requirements.

cost is assumed adequate for simulating competitive market conditions. Some preliminary work was done using barge-truck strategies to determine possible impact on the equilibrium solution, but in-depth analysis will be required before any realistic conclusions can be made.

PROGRAM AND SCOPE

The computer model design is directed towards identifying major candidates for abatement byproduct production and consumption. From a data bank maintained at the TVA National Fertilizer Development Center, design and operating inputs were cataloged in the computer for existing U.S. contact and chamber H_2SO_4 plants. Capital and operating costs for mining S by the Frasch process, transporting and storage of S, manufacturing acid by the contact process, storage of acid, and controlling acid plant tail gas emission were calculated to determine competitive costs of S and acid production.

Development of an accurate transportation data base for computing shipping costs for S and acid contributed in a major way to the value of the study since shipping cost is a significant and essential element in the price.

Power plant design and operating data provided in the FPC Form 67 data base were used to characterize key design and operation parameters of all power plants in the U.S. For this effort, only boilers burning coal or oil are of interest. Parameters such as fuel type, S in fuel, heat rate, fuel consumed, on-stream time, age of boiler, etc., are vital. Possible output of byproducts was calculated for each power plant, given the level of SO_2 control designated by June 1976 SIP standards. For boilers where scrubbing was needed, 90% removal efficiency was assumed. However, scrubbing was used only on the number of boilers necessary to bring the plant into compliance. The most likely candidates for use of recovery compared to low-S fuel or limestone scrubbing were identified. A mathematical statement of the model is presented in Appendix B.

ELEMENTAL S AND H_2SO_4 INDUSTRY

S is one of the most important industrial raw materials. It is used principally in the form of H_2SO_4 at some stage in the production of virtually everything we eat, wear, or use. It is referred to as the workhorse of the chemical industry. Its consumption is an indicator of the state of the economy of an individual nation or of the world. Unfortunately, however, in most uses S ends up as a residual of the production process. Recycling this residual back into productive use is a major problem facing the chemical industry.

DOMESTIC CONSUMPTION OF S

S enters into the production of many products in varying amounts, for example, from 18.090 tons of S or S equivalent per ton of uranium 235 (U-235) 0.0003 ton/ton of phenol-formaldehyde plastic molding compound. The amount of S and the equivalent H_2SO_4 consumed per ton of various manufactured products is shown in Appendix C.

The demand for S or H_2SO_4 is derived from the demand for the products outlined in Table 1. In most instances it is used in fixed proportions with other inputs in the production process. For this reason demand is inelastic in the short run but tends to become more elastic in the long run because there are very few unique uses for S. The demand is subject to only modest seasonal fluctuations. Because of the pervasive use of S throughout the industrial sector of the economy there has been a historically strong correlation between the demand for S and the index of industrial production. That is, the demand is responsive to cyclical fluctuations in business conditions and expands when industrial production rises.

In 1974 55% of all domestic S consumption was used in the manufacture of fertilizers. The balance of 45% was used in the production of the following products: plastic and synthetic products, 6%; paper products, 3%; paints, 4%; nonferrous metal production, 5%; explosives, 3%; petroleum refining, 2%; iron and steel production, 1%; and other uses, 21%. Each of the various uses included in the latter category used <1% of the S demand (8).

The distribution trends for the apparent consumption of S, by source, 1970-76, is outlined in Table 2. The distribution in 1976 mainly from domestic sources is listed as follows:

Frasch S	43%
Recovered elemental S	29%
S in other forms	8%
Imports of Frasch and recovered elemental S	16%

TABLE 1. U.S. S CONSUMPTION PATTERNS 1964-74[a]

(klong tons S)

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
U.S. demand pattern											
Agriculture (fertilizers)	3,090	3,610	4,425	4,735	4,470	4,465	4,680	4,800	5,210	5,520	5,980
Plastic and synthetic products	500	555	555	495	550	570	495	515	540	580	610
Paper products	415	430	440	400	390	365	350	320	340	370	390
Paints	505	510	520	505	490	445	420	380	390	420	440
Nonferrous metal production (Cu-U)	235	265	310	260	300	370	390	410	430	500	560
Explosives	215	230	260	265	250	260	255	255	260	280	290
Petroleum refining	155	165	190	195	180	190	195	200	220	230	240
Iron and steel production	330	295	275	220	170	125	120	105	110	110	110
Other	1,810	1,921	2,170	2,176	2,272	2,379	2,322	2,188	2,354	2,224	2,260
U.S. primary demand	7,255	7,981	9,145	9,251	9,072	9,169	9,227	9,173	9,854	10,234	10,880

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[a] Sulfur, U.S. Bureau of Mines reprint from Bulletin 667, 1975, p. 15.

TABLE 2. APPARENT CONSUMPTION OF S IN THE U.S.

(klong tons)

	1970	1971	1972	1973	1974	1975	1976
Frasch							
Shipments	6,504	6,738	7,613	7,438	7,898	6,077	5,860
Imports	539	449	269	302	954	967	731
Exports	1,433	1,536	1,852	1,776	2,601	1,295	1,198
Total	5,610	5,651	6,030	5,964	6,251	5,749	5,393
Recovered							
Shipments	1,471	1,582	1,927	2,451	2,547	2,902	3,146
Imports	998	850	869	920	1,196	930	996
Exports from the Virgin Islands	-	-	-	-	62	57	72
Total	2,469	2,432	2,796	3,371	3,681	3,775	4,070
Pyrites							
Shipments	339	316	283	212	162	237	286
Imports[b]	130	130	50	-	-	-	-
Total	469	446	333	212	162	237	286
Byproduct sulfuric acid	537	518	546	600	654	767	942
Other forms[c]	142	126	149	88	70	75	77
Total all forms	9,227	9,173	9,854	10,235	10,818	10,603	10,768

a. **Sulfur, U.S. Bureau of Mines reprint from Bulletin 667, 1975, p. 15.**

b. **Estimate.**

c. **Includes consumption of hydrogen sulfide and liquid sulfur dioxide.**

Three distinct trends in domestic consumption of S by sources are indicated in Table 2. Domestic Frasch S has steadily declined while domestic recovered S has steadily risen. BOM predicts that these two trends will continue. Although imports have become an increasingly important source of S for domestic consumption, they are expected to remain stable or even decline over the long range.

The basic reason for these trends relates to the pervasive drive for pollution control. The Frasch industry formerly enjoyed a dominant role in the S market throughout the U.S. However, since 1960 recovered S and byproduct H_2SO_4 sectors have progressively obtained control of the markets in the Western and Central States as well as a gradual penetration of the markets in the Southern States. Canadian imports of recovered S are largely confined to the northern tier of states, whereas Mexican imports of Frasch S are limited to the Florida and east coast markets. As a result the Frasch industry has gradually constricted its marketing to the Southern and Eastern States and the inland waterway system with the export trade holding at a level of 1-2 Mtons.

Long-term projections of S demand in the U.S. are shown in Table 3 (9).

ORGANIZATION OF FRASCH S PRODUCTION, DISTRIBUTION, AND HANDLING

BOM reports the production of S in all forms in 1976 at 10.707 Mlong tons (5); elemental S was produced by 69 companies at 182 plants in 32 states. Ten of the largest companies own 57 plants and account for 75% of the output. The production was concentrated in Texas and Louisiana accounting for 68% of the total output. The Frasch S was produced in these two states at 12 mines.

TABLE 3. U.S. S DEMAND FORECAST

(Mlong tons)

	Forecast			
	1976	1980	1985	1990
Fertilizer	6.4	7.5	9.3	11.0
Industrial	4.5	5.3	6.0	6.8
Total	10.9	12.8	15.3	17.8

The mines are owned by the following companies:

Company	No. of mines	State
Freeport Minerals	3	Louisiana
Texas Gulf	5	Texas
Texas Gulf	1	Louisiana
Duval	1	Texas
Jefferson Lake Sulfur	1	Texas
Farmland Industries Corporation (purchased from Atlantic Richfield Corporation 11-76)	1	Texas

Five of the largest mines account for 82% total Frasch output and 48% of the total production of S in all forms (8).

Frasch S production is a mining operation. Wells are sunk into S-bearing strata, S is melted by hot water injected into the strata, and the molten S is pumped out. The molten S is pumped from the well to either heated tanks for storage as a liquid or to vats where it cools and solidifies.

About 75% of the total mining costs of Frasch S is variable, such as the cost of natural gas to heat water, water treatment, labor, and operating supplies (10). The cost of hot water to melt the S is by far the most important cost and will differ drastically from mine to mine as water requirements and fuel cost differ. In an analysis prepared for this study the cost of natural gas was varied from \$0.20-\$3.00/kft^3 with an intermediate value of \$1.00/kft^3 (6). Water requirements or water rate varied from 1600 gal/ton of S produced to 9000 gal/ton of S. Results of the cost calculations (in terms of third quarter, 1974 dollars) are presented in Appendix D, Tables 1-3.

These results indicate that the lowest capital investment and operating costs are associated with mines having low water rates and that cost increases markedly with increasing natural gas costs. For operation where the major variables are constant, i.e., water rate and natural gas cost, the usual economies of size prevail.

The development of a S dome can be compared to the punching of pins in a pin cushion. Each well punched into a S dome formation has an expected life of 1-2 yr. At any time the S mine can have several wells operating in parallel. The number of wells depends primarily on the short-run market demand. As the mining process for a given dome reaches the mature stage, operating costs increase at an increasing rate due to the increased water and energy requirements. This incremental increase causes the supply price of S to rise to a point where it is no longer economical to continue mining the S dome.

Most molten S is shipped in liquid form by water from the mines or transshipment terminals on the Texas and Louisiana Gulf Coast to the marketing terminals. The basing point for the Gulf Coast market is Port Sulphur.

Marketing terminals are strategically located either on the inland waterway system or along the east coast adjacent to ports served by deepwater vessels. From the marketing terminal, molten S is transported by barge, truck, or rail directly to the point of consumption at a S-burning acid plant. A map of the relative locations for S terminals is presented in Figure 2. March 1975 transport rates were used in this study. Rates were projected to 1978 with an inflation factor of 1.15.

Cost data were estimated for S-marketing terminals serving H_2SO_4 plants in eastern U.S. (11, 12). The data obtained are presented in Appendix E in terms of third quarter, 1974 dollars. As expected, increasing the size of the terminals decreases the unit operating costs. Terminals that handle only molten S have lower costs than terminals which reship both solid and liquid S. Storage requirements added, on the average, \$2.47/ton to the cost of S on the inland waterway system and \$1.20 at deepwater terminals in Florida and the east coast. These data were used in the program to calculate the production cost of H_2SO_4 for this study.

The delivered cost of S to each acid plant in the model is based on \$60/long ton for S f.o.b. Port Sulphur plus transportation from Port Sulphur through marketing terminals by either truck or rail to the acid plant, whichever is lower cost. The least-cost mode for transporting S was extended to cover a relative comparison of rail transportation from Port Sulphur versus water transport--terminal throughput--truck or rail to the acid plant. This least-cost mode was selected in all cases for S delivered to a given acid plant.

Most of the large H_2SO_4 users own and operate captively their acid production plants. Such plants are located in close proximity to the major markets for the prime product (chemicals) or close to the raw material inputs used in the production process (fertilizers). Although many companies that produce H_2SO_4 are industrial giants, there is very little opportunity for concentration in the acid market because of the pervasive use of H_2SO_4 in the many sectors of the industrial economy. That is, no single acid producer uses enough S to exercise significant control over the S market. A breakdown of the top 20 largest producers of H_2SO_4 is presented in the analysis section of this report.

S PRICE HISTORY

The average annual price f.o.b. mine or S plant in dollars per long ton for Frasch and recovered S reported to BOM from 1954-76 are presented in Table 4.

It is noted that the cyclical fluctuation in business activity in the domestic economy during the 1958 and 1961 recessions did not affect S prices. This situation prevailed over several decades prior to 1965 due to the existence of ample Frasch stocks under the control of a few major producers. This was followed by a period of short supply coupled with the rapid growth of the fertilizer industry which resulted in abnormally high prices in 1967 and most of 1968 when an oversupply developed. The oversupply caused a general collapse of the S market lasting through most of 1973. Then prices

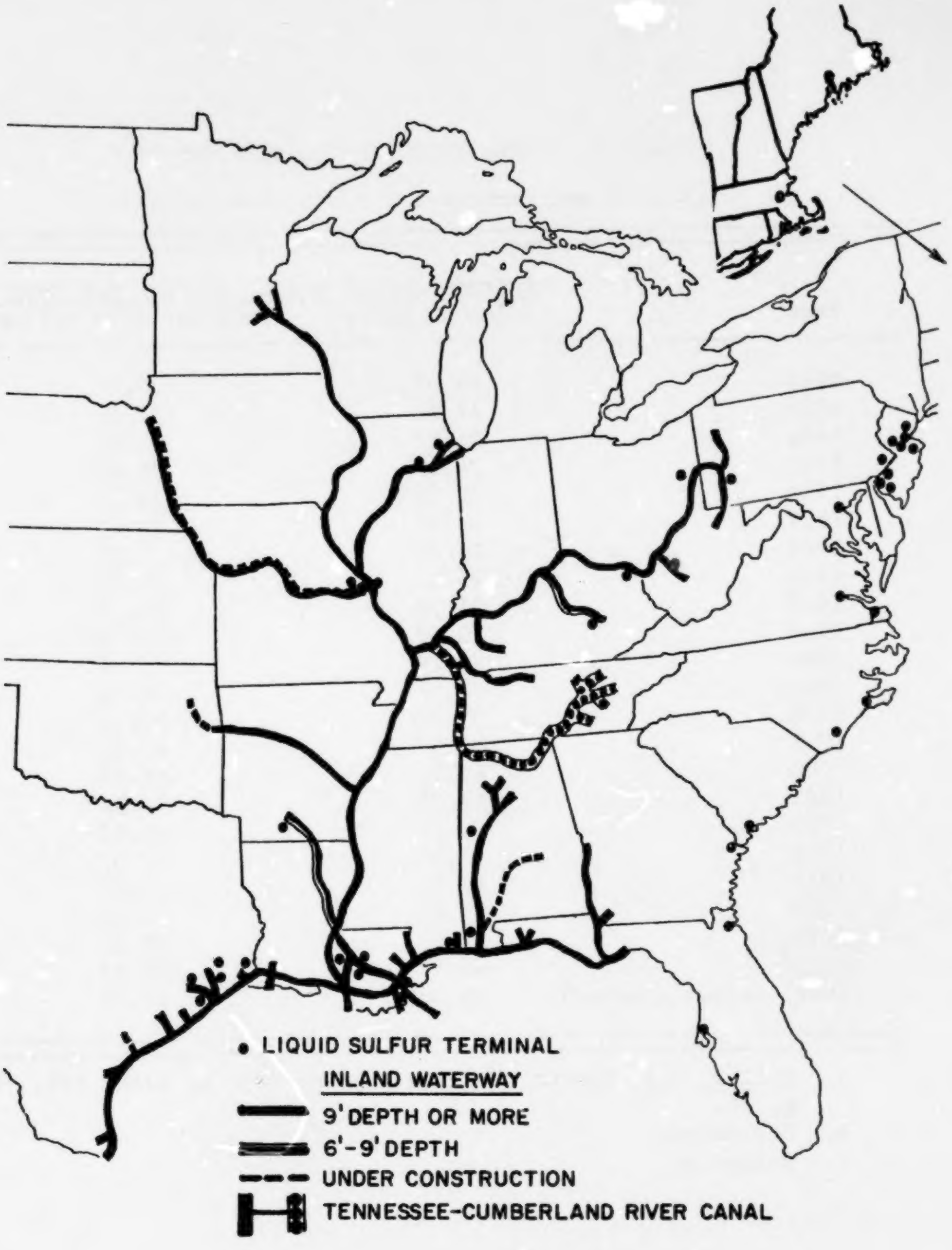
LIQUID SULFUR TERMINAL
INLAND WATERWAY
9' DEPTH OR MORE
6'-9' DEPTH
UNDER CONSTRUCTION
TENNESSEE-CUMBERLAND RIVER CANAL

Figure 2. Geographic distribution of S terminals.

TABLE 4. TIME-PRICE RELATIONSHIP FOR S[a]

(Frasch and recovered S f.o.b. mine/plant)

Year	Average annual price, dollars per long ton	
	Actual prices	Constant 1973 dollars
1954	26.65	45.97
1955	27.94	47.44
1956	26.49	43.50
1957	24.41	38.62
1958	23.82	36.76
1959	23.46	35.60
1960	23.13	34.57
1961	23.12	34.10
1962	21.75	31.70
1963	19.99	28.76
1964	20.19	28.64
1965	22.47	31.30
1966	25.77	34.92
1967	32.64	42.83
1968	40.12	50.59
1969	27.05	32.55
1970	23.14	26.42
1971	17.47	19.07
1972	17.03	17.98
1973	17.84	17.84
1974	28.88	28.18
1975[b]	46.50	38.72
1976[c] (first quarter)	55.00	43.55

[a] Sulfur, U.S. Bureau of Mines reprint from Bulletin 667, 1975, p. 16.

[b] Preliminary.

[c] Estimate.

rose to an average of \$51.19/ton f.o.b. mine/plant in 1976 followed by an apparent stabilizing trend. The average price for recovered S during this same period was \$13.50/ton lower f.o.b. plant, as compared to Frasch S price.

S is normally sold under long-term contracts direct to industrial consumers and priced on a delivered basis at regional terminals. The regional terminal prices vary with location. Export prices are determined independent of domestic prices. The f.o.b. or f.a.s. gulf port prices published in the Chemical Marketing Reporter and other journals reflect spot purchases. Generally the quoted prices for spot and contract sales are the same, but with no formal commodity exchange for S it is difficult to determine the exact S price at any given point in time. The current published price in the Chemical Marketing Reporter is \$65/long ton f.o.b. gulf ports. The price assumed for this study is \$60/long ton f.o.b. Port Sulphur.

S RESERVES

G. H. K. Pearse recently completed a study on the long-run S supply for North America (1). He projects the long-run supply price gradually increasing from \$10-\$40/ton f.o.b. mine in 1970 dollars (about \$50 in 1974). The resulting S supply price increase will encourage the relatively inefficient Frasch and native S mines to become producers over time. He projects that the current S reserves in the U.S. from conventional sources (Frasch process, native ore, petroleum, natural gas, sulfide ores, and pyrite) in the amount of 290 Mtons will be mined out at current production rates, about 12 Mtons/yr, by 2000. During the same period it is estimated that 110 Mtons of S will become available from oil shales and coal gas, giving a total cumulative production of 400 Mtons. The cumulative demand in the U.S. is estimated to be 550 Mtons by 2000, leaving a deficit of 150 Mtons of S (513.95 Mtons of H_2SO_4).

BOM estimates the U.S. reserves at 230 Mtons (8). This includes reserves of primary S deposits of the elemental, pyrite, and sulfate types. Such reserves are defined as S that is recoverable at present price levels using current technology.

They have also defined "other identified S resources" as S potentially recoverable from identified deposits at all price levels by full utilization of current technology. The domestic reserves identified in this classification amount to 400 Mtons. No attempt is made in the latter estimate to associate the estimated supply price with specific reserve sources. A study in this area is needed.

IMPACT OF ENVIRONMENTAL REGULATIONS ON S PRODUCTION

Frasch S Production

There are relatively few environmental problems associated with the Frasch sector of the industry. The major centers of production are located in remote undeveloped areas and the molten S product which is produced and distributed directly to the consumer poses no environmental problem. However, the small portion of elemental S that is stored and distributed in the solid form (referred to as vatted S) does cause a dust problem. Special handling techniques have been developed to overcome the dust hazard. It is estimated that 95% of the elemental S distributed to S-burning acid plants is handled in the liquid form.

Recovered S Production

The growth in the recovery of S from natural gas since the mid-1950's has been one of the most significant trends in the S market. The principal sources of recovered S are the hydrogen sulfide (H_2S) contaminants in sour natural gas and the organic S compounds contained in crude oil. Recovery is mainly in the elemental form. Its production has been stimulated by the increasing demand for low-S fuel as an air pollution control measure. Recovered elemental S accounted for 29% of the total domestic production of S in all forms in 1976 (3). It was produced by 51 companies in 137 plants in 27 states. The five largest recovered elemental S producers were Chevron USA Inc., Exxon Company USA, Getty Oil Company, Shell Oil Company, and Standard Oil Company of Indiana. Together their 41 plants accounted for 53% of the recovered elemental S production in 1976. Future recovery of S from natural gas is likely to decline as gas supplies drop.

Byproduct H_2SO_4 Production at Smelters

In the smelting of nonferrous sulfide ores, primarily copper (Cu), lead (Pb), and zinc (Zn), the S is converted into sulfur dioxide (SO_2) which can be recovered from stack gases in the form of H_2SO_4. The acid is referred to as byproduct H_2SO_4. In practice only the more highly concentrated portion of the smelter gases are used to produce H_2SO_4. Because of the remote location of most nonferrous metal smelters the pollution control laws allow intermittent controls for the lean streams of the SO_2 in the stack gases.

The S contained in byproduct H_2SO_4 produced at Cu, Pb, and Zn smelters during 1976 amounted to 9% of the total domestic production of S in all forms. This represented a 23% increase in output as compared to 1975. It was produced by 13 companies at 24 plants in 13 states. The five largest producers of byproduct H_2SO_4 were American Smelting and Refining Company, Magma Copper Company, Kennecott Copper Corporation, Phelps Dodge Corporation, and St. Joe Minerals Corporation. Together their 14 plants produced 71% of the output during 1976 (3).

H_2SO_4 Production in S-Burning Acid Plants

All H_2SO_4 plants, particularly the older ones, have problems in controlling the amount of pollutants in their tail gases required by air pollution control laws. The SIP standards in most states require the conversion efficiency of S to H_2SO_4 to be equal to or >99.7% efficient. This means that a major portion of the existing plants must add a retrofit tail gas cleaning system in order to comply with the air pollution control laws. A detailed discussion on the retrofit alternatives for H_2SO_4 plants is outlined in Appendix F.

DOMESTIC CONSUMPTION OF H_2SO_4

In 1974, 90% of the S consumed in the U.S. was either converted to H_2SO_4 or produced directly in this form. H_2SO_4 is considered to be the most important of the mineral acids. In 1974 H_2SO_4 was produced at 150 plants in 42 states (13).

H_2SO_4 is produced by burning S or S-bearing materials to form SO_2. The SO_2 is oxidized by air in the presence of a catalyst to form SO_3. The SO_3 is then passed through an adsorption tower where it is absorbed in recirculating concentrated acid. This process produces concentrated acid of high purity; compact plants of high capacity are feasible.

Sources of S or SO_2 for the manufacture of H_2SO_4 include (1) elemental S, (2) pyrites, (3) gypsum, (4) petroleum products, (5) smelter off-gases, and (6) waste gases from burning fossil fuels. In 1975 a brimstone-based acid accounted for 91% of the total H_2SO_4 production, followed by nonferrous smelter gases at 7% and all other raw material sources at 2%.

H_2SO_4 capacity and production have grown slowly. In 1967 H_2SO_4 capacity was 36.93 Mtons. The average growth rate has been approximately 3.5% annually; and, by 1975, capacity had grown to 48.18 Mtons. Based on current announcements of new plants, H_2SO_4 capacity by 1980 should be approximately 51.0 Mtons.

In 1967, U.S. production of H_2SO_4 from all sources was 28.8 Mtons, representing an average operating rate of 78% of capacity (13). In the following 7 yr, a general improvement in operating rates for H_2SO_4 plants took place, reaching a peak of almost 90% of capacity during the phosphate fertilizer shortage of 1973-74. In 1975, with the addition of almost 10 Mtons of additional capacity the average operating rate for the industry dropped to only 67% of capacity. Production of H_2SO_4 from all sources was in excess of 32.3 Mtons.

Almost all plants in the U.S. today are contact plants. Chamber plants, which are being phased out, now comprise only 0.2% of total plant capacity compared to 3.5% in 1967.

The use of spent H_2SO_4, the second most common process, has decreased over the past 8 yr from a high of 20.5% of capacity in 1967 to 17.4% in 1975. It is expected that use of spent H_2SO_4 will drop to 16.5% of capacity by 1980.

Production from smelter operations has been increasing. In 1967, the percent of total capacity for plants associated with the smelters was only 8.5. By 1975, it had grown to 12.3% and is expected to continue to a high of 14.7% by 1980. The availability of this acid for fertilizer use, however, may be limited because of its use in the Southwest for leaching Cu and U ores. Table 5 lists the capacity, production, and operating rates for H_2SO_4 in the U.S. for the years 1967-80 (14).

TABLE 5. U.S. H_2SO_4 MARKET STATISTICS

(Mtons of material)

Product	1967	1970	1973	1974	1975	1976	1977	1978	1979	1980
Total Sulfuric Acid										
Capacity	36.93	36.71	39.22	38.69	48.18	48.54	49.72	50.41	50.89	51.01
Production	28.82	29.53	31.95	34.18	32.37					
Operating rate, %	(78.0)	(80.4)	(80.0)	(88.3)	(67.2)					
Smelter Sulfuric Acid										
Capacity	3.14	3.39	3.81	4.14	5.97	6.67	6.82	7.38	7.38	7.50
Total capacity, %	(8.5)	(9.2)	(9.7)	(10.7)	(12.3)	(13.7)	(13.7)	(14.6)	(14.5)	(14.7)
Production	1.25	1.84	2.05	2.24	2.63					
Operating rate, %	(39.7)	(54.1)	(54.0)	(54.1)	(44.0)					
Spent Sulfuric Acid										
Capacity	7.56	7.58	8.60	8.32	8.40	8.41	8.41	8.41	8.41	8.41
Total capacity, %	(20.5)	(20.6)	(21.9)	(21.5)	(17.4)	(17.3)	(16.9)	(16.7)	(16.5)	(16.5)
Production[a]	1.08	1.27	1.56	0.75	0.95					
Chamber Process Plants										
Capacity	1.28	0.67	0.30	0.14	0.12	0.07	0.07	0.07	0.07	0.07
Total capacity, %	(3.5)	(1.8)	(0.8)	(0.4)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Production	0.84	0.32	0.11	0.13	0.10					
Operating rate, %	(66.0)	(48.2)	(35.4)	(93.0)	(83.9)					
Sulfur-Burning Contact Plants										
Capacity	24.94	25.08	26.51	26.09	33.70	33.39	34.42	34.55	35.03	35.03
Total capacity, %	(67.5)	(68.3)	(67.6)	(67.4)	(70.0)	(68.8)	(69.2)	(68.5)	(68.8)	(68.7)

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a. Refortified acid only.

END USE ANALYSIS OF S AND H_2SO_4 IN FERTILIZER PRODUCTION

PHOSPHATE FERTILIZER MARKET

While S and H_2SO_4 have many uses, it is estimated that about two-thirds of the total U.S. consumption of S in all forms is used in the fertilizer industry (15). The balance of consumption was for a variety of uses in essentially every sector of the domestic manufacturing industry. In 1976 preliminary data indicate that 6.4 Mtons of S was used in the production of fertilizer (Table 6). Ninety percent of the total went to the production of phosphoric acid (H_3PO_4) and normal superphosphate. Thus, any analysis of the future of the S and H_2SO_4 market must consider the prospects of the phosphate fertilizer market. The following is a review of the production and use patterns that have taken place in the U.S. phosphate fertilizer market in the past few years and a discussion of the future U.S. outlook for the phosphate industry.

TABLE 6. U. S. CONSUMPTION OF S IN ALL FORMS BY END USE

(klong tons S equiv)

	1974	1975	1976
H_2SO_4			
Fertilizer acid			
H_3PO_4	4,945	5,410	5,560
Normal superphosphates	405	290	230
$(NH_4)_2SO_4$ and other	685	670	610
Total fertilizer acid	6,035	6,370	6,400
Industrial acid	3,715	3,080	3,285
Total H_2SO_4	9,750	9,450	9,685
Nonacid	1,250	1,200	1,215
Total in all forms	11,000	10,650	10,900

Phosphate Consumption Patterns

Between 1945 and 1974, the U.S. phosphate fertilizer market has averaged an annual growth rate of almost 4.5%/yr (16). Over this period, the market has been characterized by several major cyclical movements; however, market growth has exhibited a stable upward movement. In recent years, there has been an indication that phosphate use by farmers has begun to level off (Table 7). Soil test results have shown an accumulation of phosphorus (P) in the soil in some areas, and application rates on the nation's major crops appear to be approaching optimum levels under today's cropping practices and management.

In 1975 phosphate fertilizer use declined by more than 10%. Analysts generally agree that this decline was caused by an imbalance in the input and output price structure faced by the farmer during the year. In relation to the prices received by the farmer for his crops, fertilizer price levels were too high; and the farmer curtailed fertilizer use. With an improvement in the benefit to cost ratio for the farmer in 1976, phosphate fertilizer use recovered the lost demand of the 1975 season and exceeded its previous highs by almost 200,000 tons of P_2O_5 (17). While this recovery was significant, it left in doubt the question of the future growth pattern for the phosphate market.

Some indication of the future growth in phosphate fertilizer demand can be found by looking at the recent history of average rates of application on the four major crops grown in the U.S. (Table 8) (18). Cotton producers, for example, have not changed phosphate application levels since 1964, responding only to changing market conditions as determined by cotton prices. Until last year, when phosphate application rates reached all time highs, corn had shown the same pattern. With application rates and the percentage of the planted acreage receiving phosphates appearing to be relatively constant, acreage planted becomes the key factor in forecasting the future demand for phosphate fertilizers in the U.S. In recent years, planted acreage has been at an all time high as government policy has been geared to stimulating maximum farm production. High levels of exports of farm products at very favorable prices in response to food shortages in many parts of the world have played an important part in the farm picture in the past few years.

But this situation has been changing rapidly. Grain-producing countries have had good weather conditions, are reporting bumper crops, and are actively seeking export markets. In addition, some of the major importing nations are also in the midst of harvesting a record crop production and establishing buffer stocks as a future hedge against poor crop years. These factors make forecasting the future national agricultural policy difficult and clouds the outlook for the short-term phosphate fertilizer market.

Projections of phosphate fertilizer use in 1980 which were made prior to the 1976 recovery indicate a range between 5 and 6 Mtons of P_2O_5 (19). Including the 1976 recovery projections of 1980, demand has varied from 5.5-6.3 Mtons P_2O_5, centering around 5.8 M (20). If phosphate use falls within these suggested ranges, the average annual growth rate for the next few years will remain below the long-term average for the industry.

TABLE 7. U.S. PHOSPHATE CONSUMPTION

(Tons of P_2O_5)

Fiscal year	Total P_2O_5 consumption	P_2O_5 in mixtures	Direct application materials			Diammonium phosphates
			Superphosphates	Ammonium phosphates	Total	
1955	2,283,660	1,821,087	291,406	84,617	462,573	113
1960	2,572,348	2,033,316	287,335	171,329	539,032	35,278
1961	2,645,085	2,069,425	303,256	188,398	575,660	63,482
1962	2,807,039	2,219,444	313,860	204,768	587,595	110,074
1963	3,072,873	2,473,599	318,415	205,457	599,274	177,487
1964	3,377,841	2,704,985	382,287	215,604	672,856	244,271
1965	3,512,207	2,816,056	403,403	204,401	696,151	302,088
1966	3,897,132	3,110,784	506,351	220,908	786,348	417,821
1967	4,304,688	3,502,897	517,470	223,761	801,791	451,452
1968	4,453,330	3,579,140	566,120	227,288	874,190	608,296
1969	4,665,569	3,724,237	656,713	207,448	941,332	723,786
1970	4,573,750	3,709,062	608,338	183,688	864,697	726,486
1971	4,803,443	3,943,372	610,969	178,878	860,071	814,938
1972	4,863,738	3,997,280	620,059	174,277	866,458	883,795
1973	5,085,162	4,237,591	576,580	201,423	847,571	1,073,198
1974	5,098,626	4,271,429	576,497	193,000	827,197	1,051,416
1975	4,510,979	3,717,825	566,953	175,899	793,154	1,038,091
1976	5,215,246	4,422,380	564,667	228,199	792,866	1,486,950

TABLE 8. AVERAGE PHOSPHATE FERTILIZER APPLICATION RATES

FOR MAJOR CROPS IN THE U.S.

(Lb/acre)

Year	Corn	Cotton	Soybeans	Wheat
1964	33	30	3	12
1965	40	32	5	12
1966	49	32	9	13
1967	51	30	9	16
1968	57	31	9	15
1969	56	31	11	15
1970	63	27	10	15
1971	54	27	10	15
1972	57	30	13	16
1973	54	32	13	17
1974	54	31	11	18
1975	50	21	10	15
1976	60	28	12	19

Phosphate Production and Trade Patterns

The phosphate fertilizer market is made up of several different types of products that have different S requirements. These can be classified as normal superphosphate, concentrated superphosphate, ammonium phosphates, liquid mixtures, and granular mixed fertilizers. Depending upon the grade of phosphate rock used, S requirements for the production of normal superphosphate range from 0.60-0.65 ton of S per ton of P_2O_5, concentrated superphosphate from 0.65-0.70, and wet-process H_3PO_4 from 0.90-0.95 (21). The P_2O_5 content of ammonium phosphates and most fertilizer mixtures is derived from wet-process H_3PO_4. Because of the wide range of S requirements, the future phosphate product mix is an important factor in determining the outlook for the S and H_2SO_4 market.

Production of wet-process H_3PO_4 and the major phosphate fertilizer materials in the U.S. is shown in Table 9 (22). Between 1960 and 1976, H_3PO_4 production increased from 1.3 Mtons of P_2O_5 to almost 7 Mtons. During the same period, normal superphosphate production has steadily declined and today is <400,000 tons of P_2O_5. Concentrated superphosphate production has remained relatively constant between 1.0 and 1.5 Mtons.

The significant change in the U.S. phosphate fertilizer market has been the rapid shift from low-analysis materials to a market based almost entirely on the production of wet-process H_3PO_4. In addition to the ammonium phosphate grades, there has also been a significant gain in the liquid mixed fertilizer market which is based primarily on wet-process superphosphoric acid.

TABLE 9. U.S. PRODUCTION OF H_3PO_4 AND PHOSPHATE FERTILIZERS

(ktons of P_2O_5)

Year	Wet-process phosphoric acid	Superphosphate		Multinutrient materials			
		Normal	Concentrated	Ammonium phosphates	Other	Total	Total
1955	775,000	1,558	707	-	-	8	2,273
1960	1,325,000	1,270	986	269	131	400	2,656
1961	1,409,000	1,247	1,024	370	102	472	2,743
1962	1,577,000	1,213	960	536	113	649	2,822
1963	1,957,000	1,227	1,113	-	-	891	3,231
1964	2,275,000	1,206	1,225	-	-	1,034	3,465
1965	2,896,000	1,113	1,466	1,081	172	1,253	3,832
1966	3,596,000	1,138	1,696	1,376	239	1,615	4,449
1967	3,993,000	1,184	1,481	1,747	284	2,031	4,696
1968	4,152,000	914	1,389	1,633	215	1,848	4,151
1969	4,328,000	807	1,354	1,844	288	2,132	4,293
1970	4,642,000	670	1,474	2,092	361	2,453	4,597
1971	5,016,000	626	1,513	2,395	468	2,863	4,992
1972	5,775,000	677	1,659	2,577	570	3,147	5,483
1973	5,919,000	620	1,693	2,919	347	3,266	5,578
1974	6,186,000	698	1,719	2,654	296	2,950	5,367
1975	6,889,000	484	1,649	3,044	218	3,262	5,395
1976	6,938,000	388	1,595	3,633	232	3,865	5,848

H_3PO_4 use in the production of granular complete mixed fertilizers also remains as a significant part of the phosphate fertilizer picture.

The Canadian phosphate market is very similar to the U.S. with the exception that normal and concentrated superphosphate play a much smaller role in the total supply picture. Most of the phosphate production in Canada is made up of the various grades of monophosphate and diammonium phosphate materials.

Exports of phosphate materials to the world market now play an important role in the supply situation for the U.S. It is estimated that over 20% of the total U.S. production of finished phosphate fertilizer materials now enters world markets. Up to now the ammonium phosphates and concentrated superphosphate have been the primary products in the export market. However, in the past several years there has been a growing trend for other countries to establish phosphate product production facilities based on the importation of H_3PO_4. The U.S. has a key position in this market and is exporting substantially higher amounts of H_3PO_4 than it has in previous years. Product exports are shown in Table 10 (23).

When product production levels are related to trade tonnages, the impact of the shift to H_3PO_4-based materials is apparent. Concentrated superphosphate production has leveled off while trade levels have increased. Thus, the available supply for the U.S. market for this product has been on the decline along with supply of normal superphosphate. Ammonium phosphate production has been expanded to the point of satisfying the domestic market and allowing large gains in the export sector. Ammonium phosphates now account for over 60% of all U.S. phosphate production entering the export market.

Future Supply Patterns

The last large-scale expansion of phosphate production facilities took place from 1973 to 1975. At that time, the total wet-process H_3PO_4 capacity went from 6.4 Mtons to 8.6 Mtons P_2O_5. With the final completion of this expansion program early in 1977, the U.S. H_3PO_4 capacity stood at just over 9.0 Mtons. There have been no expansions of Canadian capacity which now contributes over 900,000 tons of P_2O_5 to the North American total (24). Between now and 1980, there are no new capacity expansions anticipated. Several possible projects have been in the planning stage for some time but cannot be included in the tabulation at this time. Should any of these units be built, U.S. capacity will exceed 10 Mtons of P_2O_5.

Over the last 15 yr, the number of normal superphosphate plants has shown a steady decline. At one time, they numbered over 200 units scattered over the country, but today they number only in the forties and are located primarily in the southeastern U.S. Faced with rising costs on all fronts, many of these plants have been converted to ammoniation-granulation facilities which use H_3PO_4 as the primary phosphate source. It is expected that normal superphosphate production will continue to decline. However, it will be a somewhat slower rate than has been experienced in the past few years.

TABLE 10. U.S. PHOSPHATE FERTILIZER EXPORTS

(ktons of P_2O_5)

Year	Superphosphate Normal	Superphosphate Triple	Ammonium phosphates	Phosphoric acid	Total all materials
1955	57	60	38	-	155
1960	31	144	46	-	221
1961	30	174	34	-	238
1962	26	228	53	-	307
1963	18	270	81	-	369
1964	39	276	159	-	474
1965	17	233	140	-	390
1966	18	294	338	-	650
1967	15	291	556	-	862
1968	19	533	556	-	1,108
1969	6	361	413	-	780
1970	8	325	448	19	800
1971	2	321	597	57	977
1972	12	393	799	22	1,263
1973	3	409	983	40	1,473
1974	6	488	876	33	1,451
1975	6	494	1,181	169	1,882
1976	2	589	1,242	216	2,049

It is doubtful that this product will disappear completely from the phosphate picture; however, its market share will remain quite small in the years ahead.

Very little in the way of capacity additions for concentrated superphosphate are expected. This product's market share will probably decline; however, it is expected that production levels will remain relatively constant over the next few years. Concentrated superphosphate will remain a popular export product for those countries that have domestic nitrogen (N) supplies and do not wish to import N in the form of ammonium phosphates.

The future supply outlook for the U.S. phosphate industry is shown in Figure 3. Total demand for phosphate materials including that entering the export market should be approaching 8 Mtons of P_2O_5. The potential supply that can be made available to the fertilizer industry if plants are operated at their historical average operating rate of 87% of capacity, and assuming the continued decline in normal superphosphate production, will balance with this level of demand by the end of the decade. Between now and 1980, however, it can be expected that the industry will operate at somewhat reduced levels moving to higher or lower levels as dictated both by domestic demand and the demands of the export market.

Implications for the S Market

From the above discussion it can be concluded that the S industry should not expect the phosphate fertilizer market to absorb any large-scale "increase" in the production of H_2SO_4 in the next few years. The shift to H_3PO_4 with its higher S requirement is almost complete so the changing product mix of the phosphate industry will have a relatively minor impact on the S market.

S demand by the phosphate industry should be variable over the next few years as operating rates change according to the demands of the export market. Between 1975 and 1980, however, estimates show that total S demand by the fertilizer industry should increase by about 1 Mtons. The industrial sector of the market is estimated to grow by 1.2 Mtons during the same period.

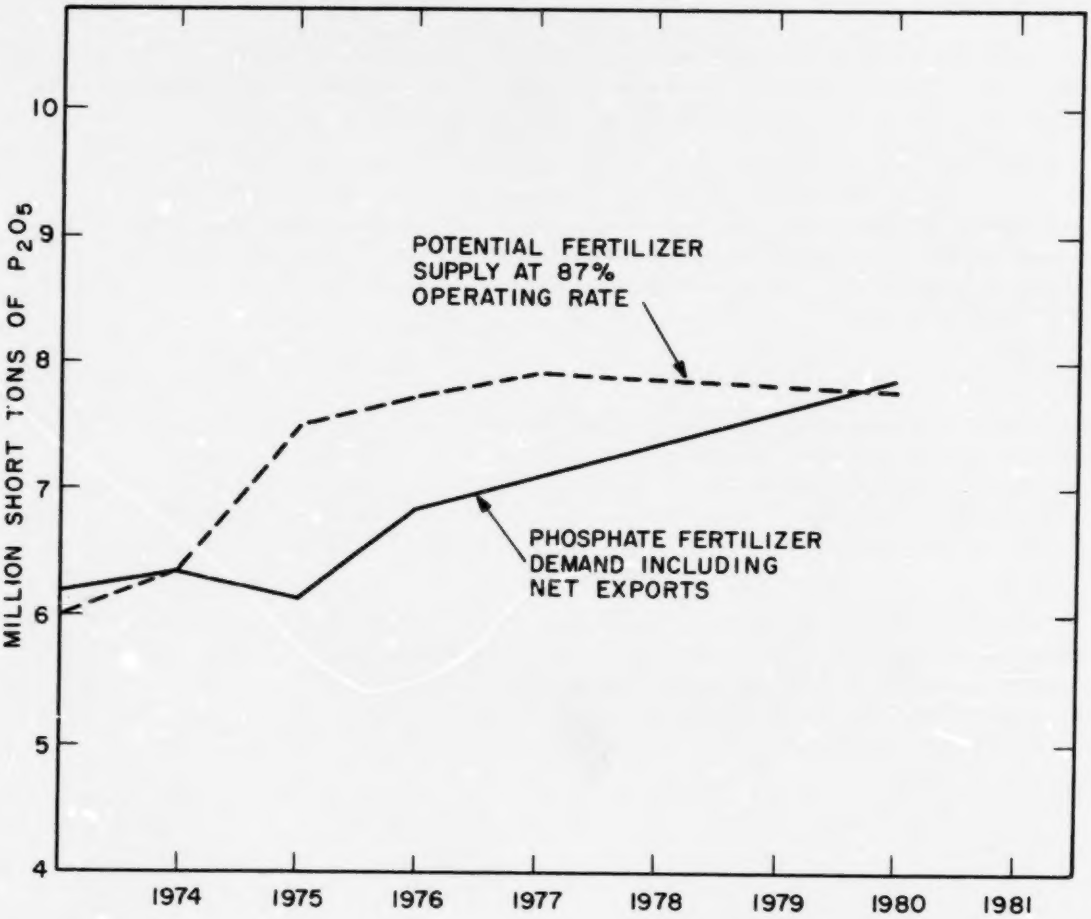

Figure 3. U.S. phosphate supply - demand outlook.

ANALYSIS OF THE POTENTIAL DEMAND FOR ABATEMENT BYPRODUCT H_2SO_4

In this study, it was assumed that the H_2SO_4 market can be simulated as though all consumption occurs at the H_2SO_4 plants and that acid-producing firms will close these plants and buy abatement acid if it can be delivered equal to or below their avoidable cost of production. Avoidable cost is an estimation of the production cost that could be avoided by closing an existing acid plant assuming abatement byproduct acid would be available in amounts equal to the plant production capacity (330 days/yr). To develop the required inputs to the model on the demand side, it was necessary to identify all potential acid producers and their avoidable costs of production. The acid plants selected include only those plants that burn elemental S as feedstock for the production of H_2SO_4.

The sludge acid plants are excluded from the analysis because of their unique operating procedure. That is, they receive sludge acid or weak acids which are decomposed to produce pure SO_2 used as feedstock to an acid plant. The sludge acid feedstock is usually supplemented with elemental S in order to efficiently produce a concentrated commercial-grade acid.

Sludge acid plants could use a regenerable product loaded with SO_2 from an FGD system by regenerating the absorbent onsite. However, this action would require considerable modification of the existing acid plant facilities. It was not included in the study.

THE EXISTING S-BURNING ACID PLANTS IN THE U.S.

TVA's computerized file of worldwide manufacturers of fertilizer and related products contains a list of 104 plants producing H_2SO_4 by burning elemental S. Total annual production capacity exceeds 35 Mtons. Fourteen of these plants are located in the 11 Western States with a production capacity of 3.04 Mtons (3). This group was analyzed separately because of the unique characteristics of the market in these states coupled with the difficulties encountered in modeling the transportation rates in the transcontinental freight zone. This is discussed further in the section dealing with the marketing of byproduct acid produced by smelters.

The acid plants located in the 37 Eastern States were considered as a potential market for abatement byproduct acid. This includes 90 S-burning H_2SO_4 plants with an annual production capacity of 32.237 Mtons based on 330 days' operation/yr. The geographic distribution of these plants by states is outlined in Figure 4 and Table 11 (14).

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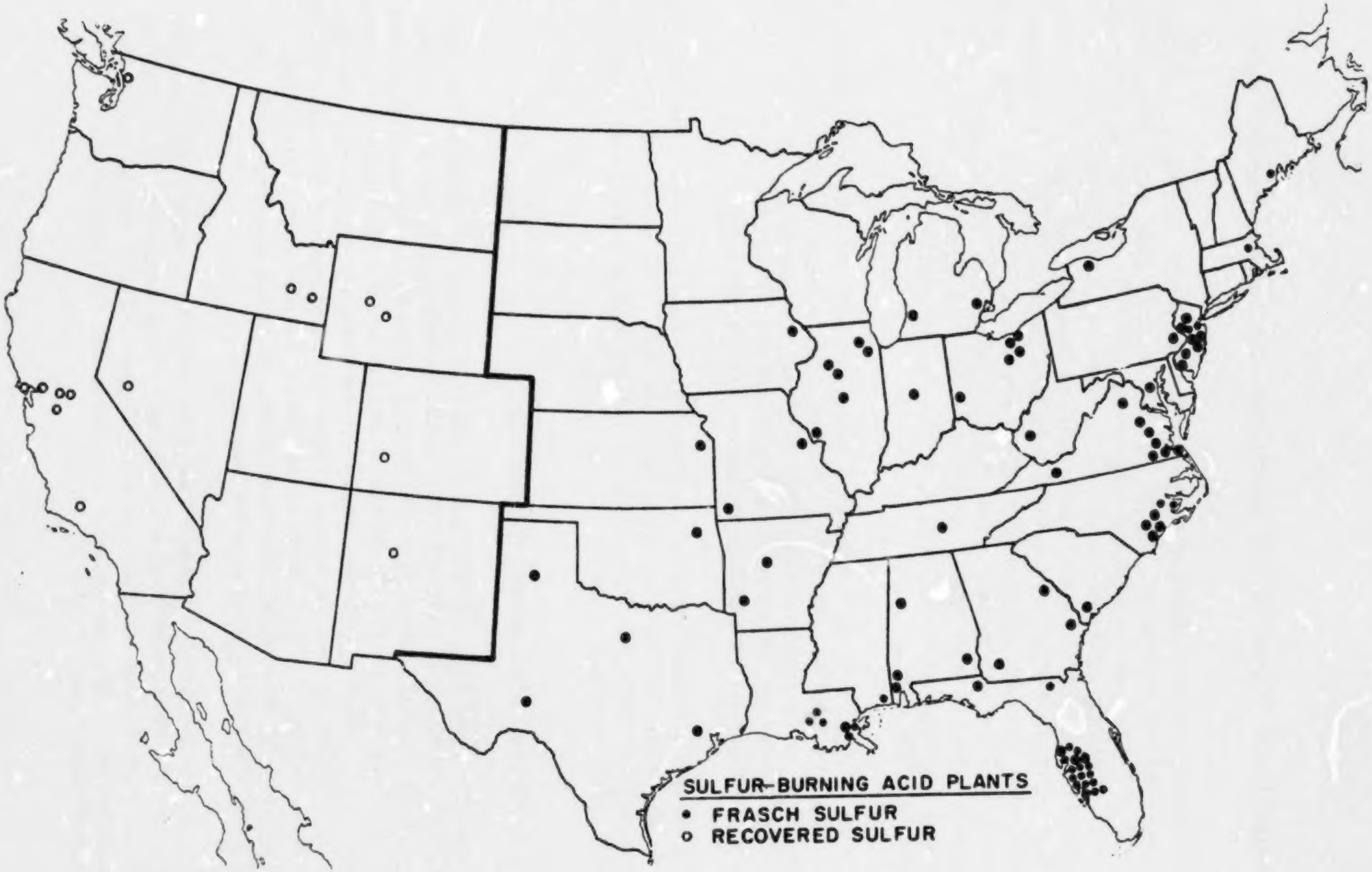

SULFUR-BURNING ACID PLANTS
● FRASCH SULFUR
○ RECOVERED SULFUR

Figure 4. Geographic distribution of S-burning acid plants (1978).

TABLE 11. U.S. S-BURNING H_2SO_4 PLANT CAPACITY (1978)[a]

(ktons - 330 days/yr)

State	Number of plants	Annual capacity	State	Number of Plants	Annual capacity
Alabama	4	342	Missouri	2	553
Arkansas	2	205	Mississippi	1	1,220
Florida	20	16,189	North Carolina	6	2,026
Georgia	3	365	New Jersey	9	1,720
Iowa	1	98	New York	1	6
Illinois	6	985	Ohio	5	665
Indiana	1	56	Oklahoma	1	110
Kansas	1	105	Pennsylvania	1	75
Louisiana	6	4,965	South Carolina	1	42
Massachusetts	1	120	Tennessee	1	132
Maryland	1	350	Texas	4	806
Maine	1	75	Virginia	8	832
Michigan	2	60	West Virginia	1	135
Total East	37 States			90	32,237

State	Number of plants	Annual capacity	State	Number of plants	Annual capacity
California	6	1,271	Nevada	1	140
Colorado	1	55	Washington	1	15
Idaho	2	1,310	Wyoming	2	110
New Mexico	1	141			
Total West	11 States			14	3,042
Total Contiguous States 48				104	35,279

a. Projected 1978.

THE IMPACT OF ABATEMENT ACID

H_2SO_4 plants are widely scattered throughout the U.S. chiefly because of the low-bulk value of the acid, difficulties in handling the acid in the bulk, and subsequent high cost of shipment as compared to handling elemental S. Therefore, acid has been traditionally produced by S-burning plants in captive use near the point of consumption. However, many existing plants are old and will soon need replacing. Some will likely shut down in 1978 because compliance with pollution control regulations will not be economical. This group should be receptive to the opportunity to buy abatement acid in lieu of building a new acid plant.

Many power plants enjoy a unique location advantage for supplying abatement acid in the existing market. This is especially true for acid plants located in the more remote areas from traditional S supplies. The most orderly way to incorporate abatement acid would be to replace the capacity of relatively high-cost S-burning H_2SO_4 plants. These are generally remotely located from S sources. The producer is given the opportunity to close his plant down and buy abatement acid if it results in a saving. The more efficient plants would continue to produce.

PRODUCTION COSTS FOR H_2SO_4

The expenses that could be saved or avoided by shutting down existing acid producers were estimated. Such expenses are delineated below:

Raw material	S
Utilities	Electric power Cooling water Processed water Boiler-feed water
Operating expenses	Labor Supervision
Capital costs	Amortized costs for maintenance of existing facilities and amortized costs of new capital investment at end of useful plant life

In the Phase I study a computer program was developed using these inputs to calculate contact H_2SO_4 production costs. Details of this program are given in the report on Phase I. For existing plants, the initial capital expenditures are handled as a "sunken investment" and, therefore, do not enter directly into the firm's decision to discontinue present production and buy abatement H_2SO_4. Only avoidable costs are considered in making this decision.

Annual costs are calculated in perpetuity using the discounted cash flow analysis method. The outlay streams are then amortized or averaged over all years in the firm's planning horizon. The cost streams are composed of:

1. Constant annual expenditures for S, utilities, and operating expenses
2. Periodic expenditures for new replacement plants
3. Maintenance of existing facilities which is assumed to grow at a compound rate

The impact of inflation is not included in the analysis. These cost streams for a new plant are presented in Figure 5.

The optimum useful life is identified as the minimum point on the average total cost curve. At this point the added capital cost savings that result from increasing useful life 1 yr equals the added maintenance saving from shortening useful life 1 yr. The average capital charge of 19.3%, identified in Figure 5, covers a range from 23-36 yr. Random effects, such as abrupt physical, economical, technological, or environmental changes, play the dominant role during this period with regard to the timing of plant replacement or shutdown.

H_2SO_4 plants built prior to 1960 were assumed to average 95.5% conversion of S to acid. Plants built between 1960 and 1975 were assumed more efficient with 97% conversion. These efficiencies, however, are not representative of plants that must operate after 1975 since emission limitations will require an efficiency of at least 99.7%. For the potential growth market, it was necessary to consider tail gas cleanup at a 99.7% efficiency level for new plants (double absorption). Capital and operating cost estimates for acid plant tail gas cleaning systems for existing plants are outlined in Appendix F. These costs, of course, must be added to the avoidable costs of existing plants.

THE DEMAND CURVE FOR ABATEMENT ACID

The avoidable costs (theoretical) are calculated at each respective acid plant location considered in the study. The major variables used in the acid plant cost generation program are outlined in Table 12 along with example values. Costs of manufacture based on data generated here indicate that most of the acid production costs range from \$25-\$45 depending on plant location, size, and age; the March 1976 price for H_2SO_4 (100% H_2SO_4 f.o.b.) was \$44.95/ton (25). Cost estimates projected for each specific acid plant are outlined as a demand schedule in Appendix G. A summation of capacity of acid plants versus avoidable cost of production is shown in Figure 6. The resulting plot defines the demand curve for abatement acid.

The demand curve is estimated by ranking all acid plants from highest to lowest cost and accumulating demand quantities to show acid cost as a function of acid plant capacity. At a very high cost of alternative supply only a few acid producers could justify buying rather than producing H_2SO_4. These plants tend to be old, low-volume producers far from S supplies. As supply cost of abatement acid declines, more acid producers would become potential customers. At low supply costs all but the largest, most modern acid plants located near S supplies could be shut down. The important implication for the present study is that small quantities of abatement acid could be marketed at high value but as the supply increases the value declines.

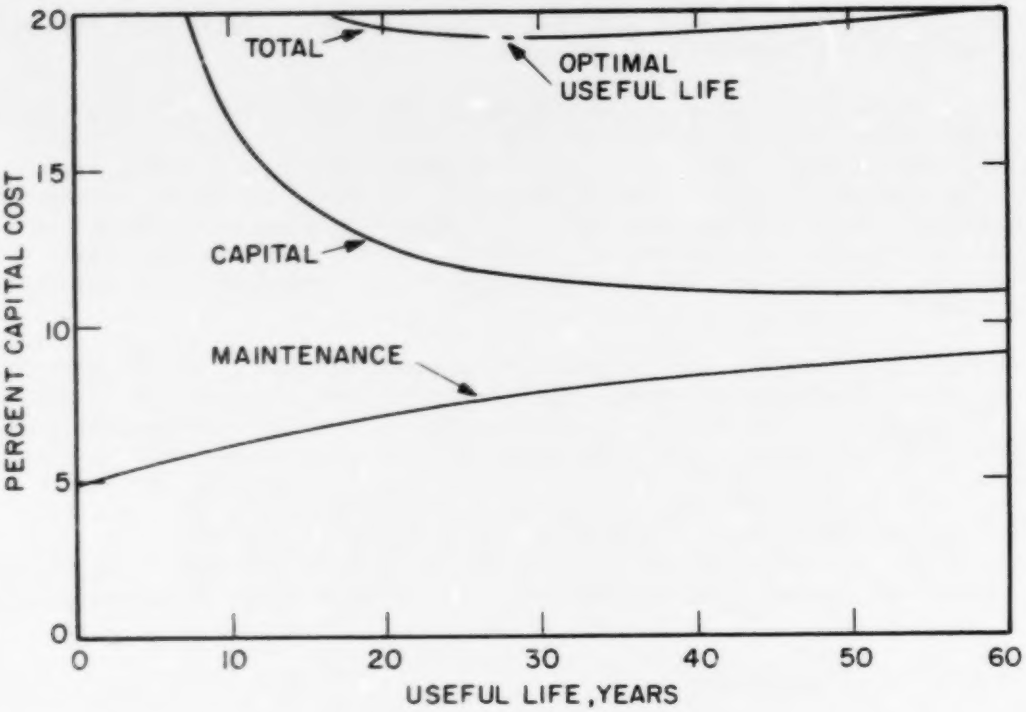

Figure 5. Amortized value of maintenance and capital outlays for new H_2SO_4 plants (assuming 11% interest and 5% compound maintenance).

TABLE 12. MAJOR PARAMETERS IN MODEL

No.	Description of variable	Example value
1	Tons of S/ton H_2SO_4 (before 1960)	0.3053
2	Tons of S/ton H_2SO_4 (after 1960)	0.3006
3	Year of technology change	1960
4	H_2SO_4 plant investment ($/ton/yr)	27.285
5	Capacity for this plant (ktons/yr)	247.5
6	Scale factor for determining investment for other sized plants	0.734054
7	Fixed conversion cost/ton ($/ton)	0.47
8	Fixed annual conversion cost ($/yr)	116.620
9	Taxes and insurance rate	0.015
10	Time preference rate for money	0.11
11	Compound maintenance rate	0.05
12	Economic useful life (yr)	34
13	Percent H_2SO_4 concentration	98
14	Port Sulphur price ($/ton S)	53.57
15	Steam plant H_2SO_4 price ($/ton H_2SO_4)	0
16	Proportion of 330 tons/day capacity estimate	1
17	Number of years considered	1
18	Year considered	1978
19	Unit cost inflation factor over 1973	1.93
20	Transportation cost inflation over 1975	1.15
21	Retrofit cost for compliance	4.41

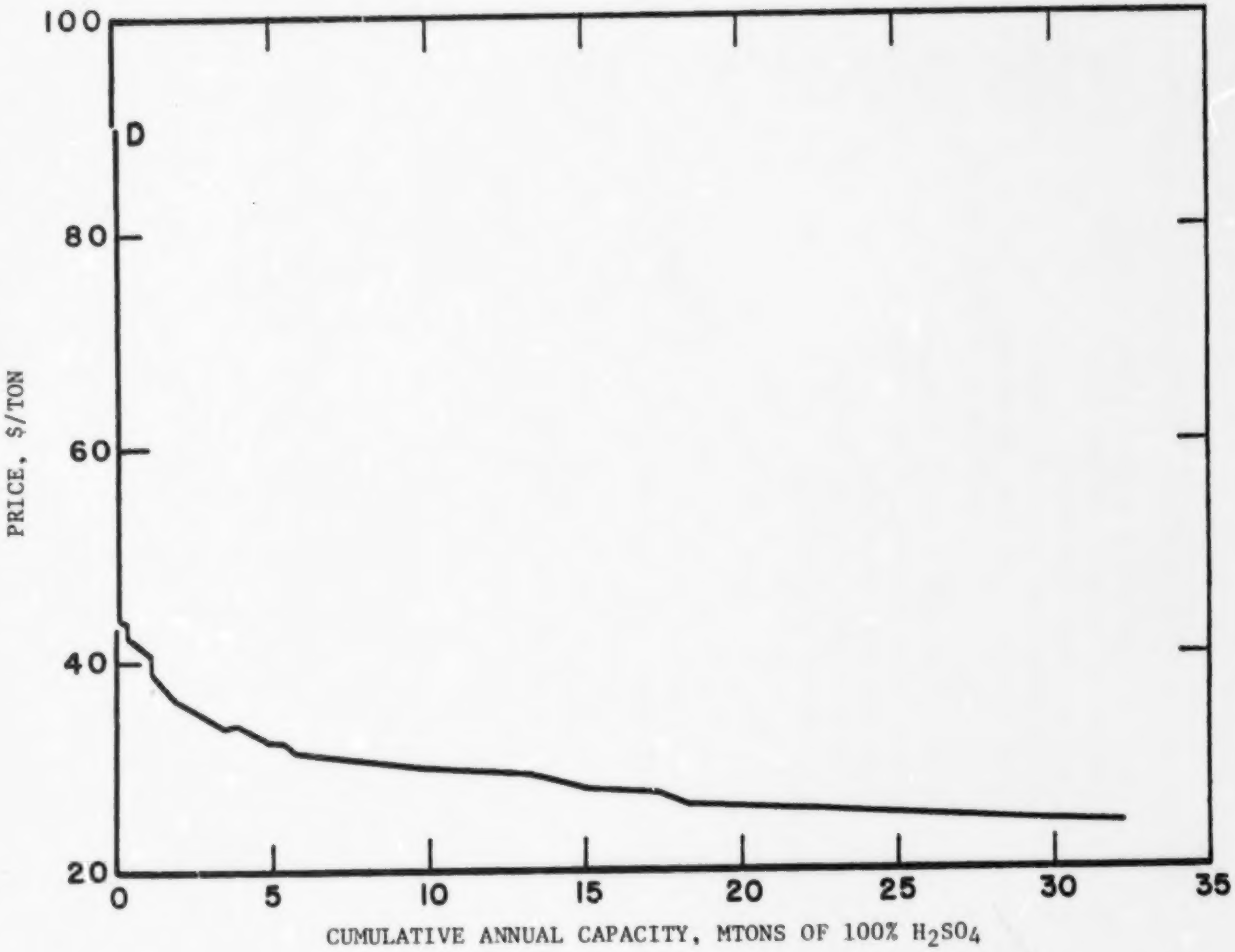

Figure 6. Abatement byproduct H_2SO_4 demand curve (Eastern States).

ANALYSIS OF THE POTENTIAL SUPPLY OF BYPRODUCT H_2SO_4 FROM SMELTERS

S contained in byproduct acid at Cu, Pb, and Zn smelters amounted to 9% of the total domestic production of S in all forms in 1976. It represents the third most important source of S in the S industry as shown in Table 2. The byproduct acid market is a well-developed market and it has been in operation a number of years. The recent increases in production outlined in Tables 5 and 6 are a direct result of the existing environmental regulations that require more stringent control of emissions.

New source performance standards for H_2SO_4 plants limit the quantity of SO_2 that may be emitted to 4 lb SO_2/ton of H_2SO_4. Proposed standards for primary Cu, Zn, and Pb smelters limit the emission concentration of SO_2 to <0.065% by vol requiring the removal of approximately 90% of the emitted SO_2. Although state regulations for existing H_2SO_4 plants and smelters are in most cases less stringent than the NSPS, there are cases where the state regulation is equal to NSPS.

END USES FOR BYPRODUCT ACID

Approximately 5% of the domestic S consumption is used for leaching of Cu and U ores with H_2SO_4. In the Cu industry it is used for the extraction of the metal occurring in deposits, mine dumps, and wastes when Cu content is too low to justify concentration with conventional flotation techniques. It is also used for the recovery of Cu from ores containing Cu carbonate and silicate minerals that cannot be treated efficiently by flotation processes. Smelter acid is also used as a reagent for the recovery of U from ores. The surplus of the byproduct smelter acid goes into the same market identified in Table 1 for acid produced from elemental S. A number of the captive use H_2SO_4 plants which closed down in the last decade are presently using byproduct acid from smelters. The most popular end use is for fertilizer production.

1978 PRODUCTION POTENTIAL

To evaluate the potential production of abatement acid from power plants in the existing S market, the marketing model must be designed to accommodate the byproduct acid from smelters. They are already established in the acid market.

The present technology assumes that the production of byproduct H_2SO_4 to control SO_2 emissions in smelter operations represents the best available technology. Since the law requires SO_2 control, the smelter operator is faced with the option of either marketing the surplus acid that cannot be used in leaching operations or neutralizing the acid to form a waste product that is acceptable to the environment. This means that a cost equivalent to the cost of neutralizing the acid could theoretically be invested in marketing the acid. A discussion including cost estimates for byproduct H_2SO_4 production from smelter gases including estimates of retrofit tail gas cleanup and limestone neutralization is presented in Appendix H. In the model it is assumed that the value of the byproduct acid is zero at the plant site.

Using a 1975 base period, it was assumed that existing S-burning acid plants and byproduct acid plants operating at smelter locations were operating at an equilibrium position in the market place. The incremental acid that is projected to be produced at both existing and new smelter locations in 1978 is assumed to be in direct competition with abatement acid that could be produced by a steam plant at a given location.

The 14 smelters located in the 11 Western States were analyzed separately from the 14 smelters in the 37 Eastern States of the U.S. Each smelter that was identified as being out of compliance by the EPA compliance data system in September 1976 was assumed to be equipped with control equipment by 1978 that increased capacity by 16% compared to 1975. Plants in compliance were assumed to increase their capacity factor by 10% in 1978 and new plants are assumed to operate at 60% capacity (100% = 330 days/yr). The geographic location of the plants considered in this analysis are outlined in Figure 7. The 1978 incremental production estimated for the Western States amounted to 849,000 tons H_2SO_4. The analysis for the smelters located in the Eastern States amounted to 811,000 tons of acid. This analysis is presented in Table 13.

The avoidable costs of production were calculated for each of the 14 acid plants located in the 11 Western States. This analysis assumed the use of recovered S from western Canada at $25/ton f.o.b. Calgary, Alberta, Canada, delivered by rail to each acid plant considered. The results of these calculations are presented in graphic form in Figure 8 as a demand curve for abatement acid for the Western States. The interpretation of this demand curve is similar to the demand curve presented in Figure 6. Assuming a zero value for the smelter acid only one smelter location at Hayden, Arizona, could deliver byproduct acid equal to or below the avoidable cost of production at an acid plant located at Helm, California. This accommodated the marketing of 111,000 tons of byproduct smelter acid in the Western States. This left a balance of 738,000 tons to be marketed in the Eastern States.

The strategy for marketing the western surplus smelter acid in the eastern market involves the use of transshipment terminals supplied by unit trains. Rail rates for unit train shipments are shown in Appendix I. The value of the acid at the transshipment terminal was assumed to be equal to the rail rate plus $1.50/ton terminal handling charge. The terminal locations selected were: Chicago, Illinois; St. Louis, Missouri; Memphis, Tennessee; Baton Rouge, Louisiana; and Houston, Texas. Two additional transshipment terminals were added in the model at Buffalo, New York, and Detroit, Michigan, in order to analyze the marketing of 200,000 tons of byproduct acid from smelters in Canada. This concept is presented graphically in Figure 9. The storage cost analysis is presented in Appendix F.

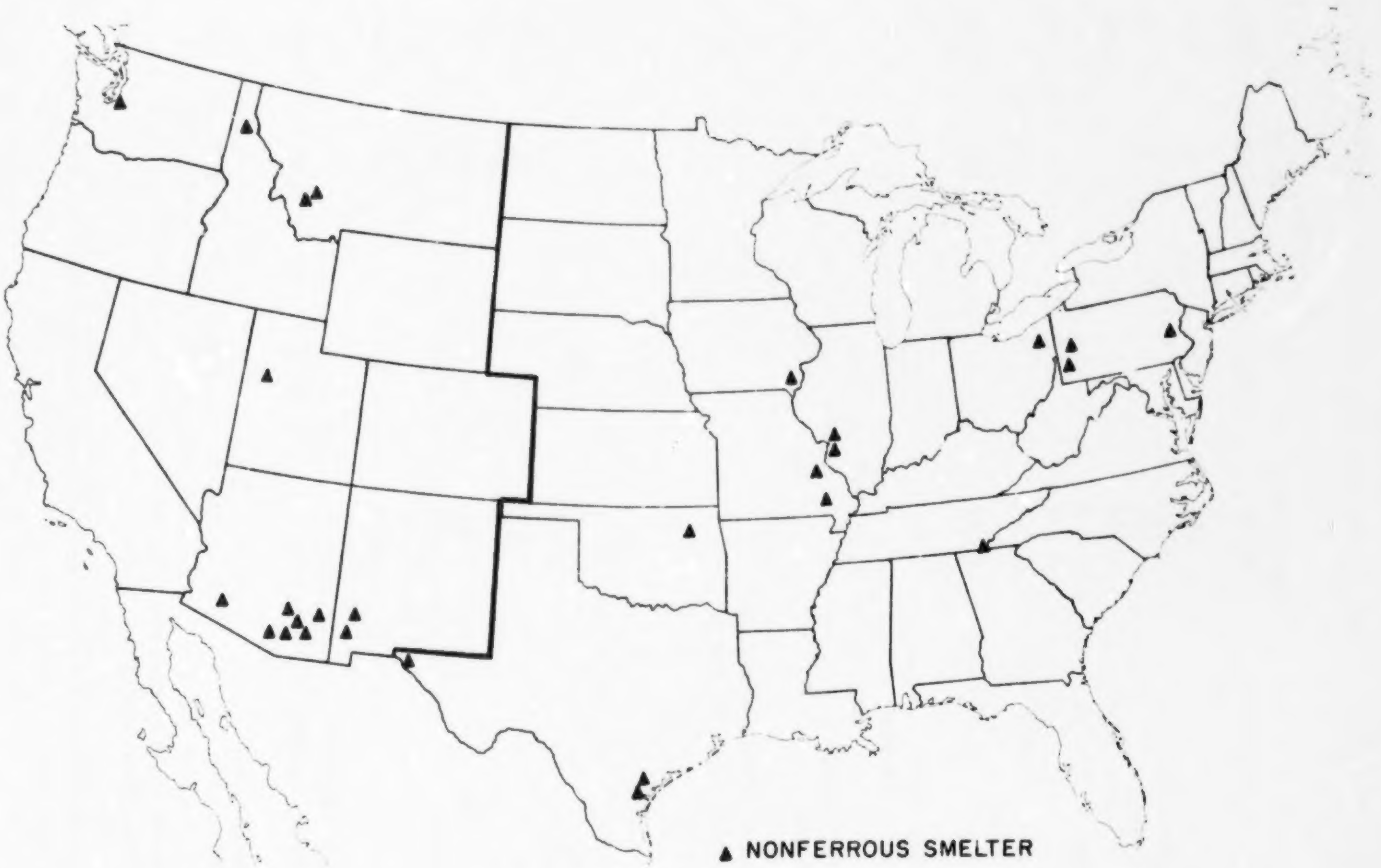
▲ NONFERROUS SMELTER

Figure 7. Geographic distribution of smelter byproduct acid plants in 37 Eastern States and 11 Western States.

TABLE 13. INCREMENTAL H_2SO_4 PRODUCTION FOR EASTERN AND WESTERN SMELTERS

1976-1978

State	Capacity, ktons	Existing		New
		In compliance	Out of compliance	
Missouri	760	190	90	480
Tennessee	1,250	-	1,250	-
Pennsylvania	579	-	500	79
Iowa	100	-	-	100
Oklahoma	91	91	-	-
Texas	286	160	-	126
Ohio	20	20		
Total	3,086	461	1,840	785
1978 increased production factor		0.10	0.16	0.60
1978 increased production		46	294	471
Total 1978 increased production estimate				811
Arizona	2,284	2,284	-	-
New Mexico	780	-	200	580
Montana	330	-	230	100
Idaho	250	-	250	-
Utah	600	-	600	-
Washington	50	-	50	-
Total	4,294	2,284	1,330	680
1978 increased production factor		0.10	0.16	0.60
1978 increased production		228	213	408
Total 1978 increased production estimate				849

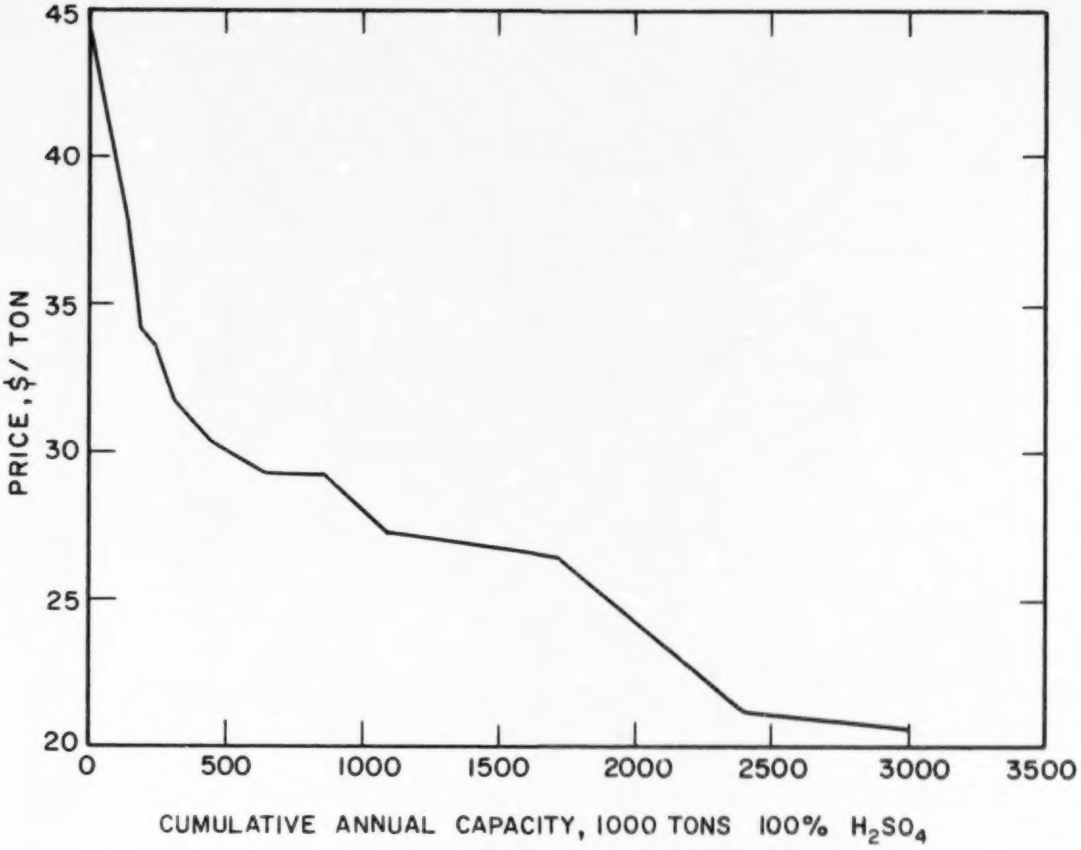

Figure 8. Abatement byproduct H_2SO_4 demand curve (Western States).

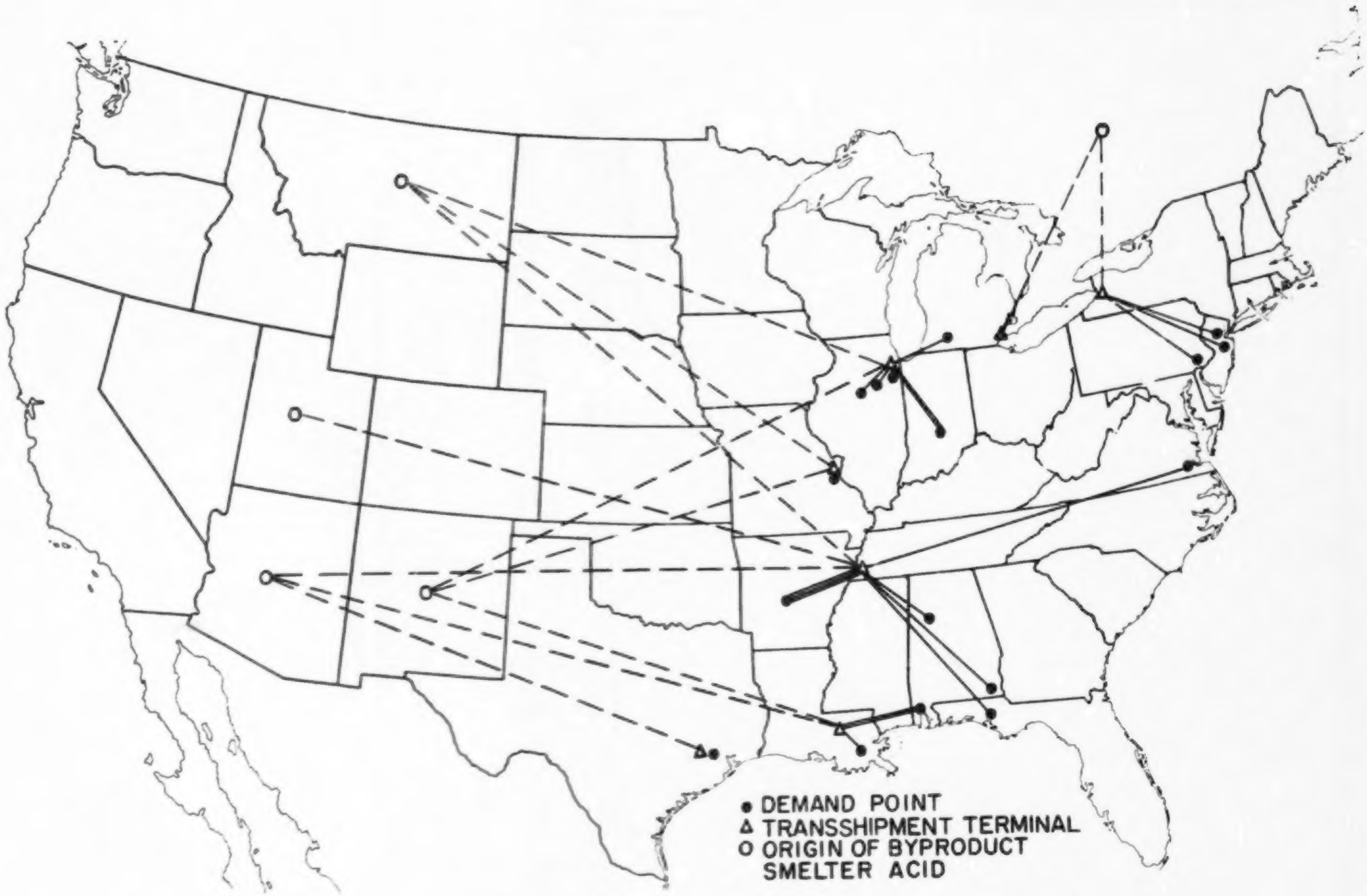
● DEMAND POINT
Δ TRANSSHIPMENT TERMINAL
O ORIGIN OF BYPRODUCT SMELTER ACID

Figure 9. Geographic distribution of assumed supply and demand for western and Canadian acid in zero ACFL model run.

In the marketing model, the seven transshipment terminals (listed above) are handled as simulated smelter-producing locations that can compete in the market with the 14 eastern smelters and the 187 power plants that are candidates for production of H_2SO_4. The results of the model runs are presented in a later section.

SO_2 EMISSION REGULATIONS AND APPLICATIONS

With the passage of the Clean Air Act Amendments of 1970, EPA was given the responsibility and authority to regulate and control air pollution in the U.S. and its territories. Among other responsibilities, the Clean Air Act required EPA to put into effect National Ambient Air Quality Standards (NAAQS) for pollutants which adversely affect public health and welfare, including SO_2, nitrogen dioxide (NO_2), particulate matter, carbon monoxide (CO), hydrocarbons, and photochemical oxidants.

SIP

The Clean Air Act required each state to adopt and submit to EPA an acceptable plan for attaining, maintaining, and enforcing NAAQS in all regions of the state. These SIP prescribed emission limiting regulations, timetables for compliance with the limitations, and measures required to ensure attainment of the standards. Unacceptable plans were returned to the states for revision or, in some cases, substitute regulations were established by EPA. While the primary responsibility for enforcing SIP regulations rests with the individual states, EPA is responsible for assuring that all implementation plan requirements are fulfilled. As a result, EPA provides technical and legal assistance to the states in enforcing SIP regulations. If any state fails to enforce its implementation plan regulations, the Federal Government may take legal actions against the noncomplying sources.

Following initial approval of most SIP in 1972, many states began submitting to EPA revisions to their implementation plan, many of which alter the emission limitations. Usually, these revisions are based on additional air quality measurement data or on a more detailed technical analysis of air pollution control strategies. When approved by EPA, these revisions become a part of the implementation plan.

FEDERAL NSPS

In addition to the SIP limitations, emissions from certain sources are restricted further by NSPS.

The purpose of these standards is to prevent the occurrences of new air pollution problems, encourage improvements in emission control technology, and provide a mechanism for controlling pollutants which EPA suspects are hazardous, but for which insufficient information is available to regulate under other provisions of the Act.

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The standards are applicable to newly constructed facilities, new equipment additions to existing facilities, and existing equipment which is modified in such a way that an increase of pollutant emissions occurs. NSPS is in most cases more stringent than SIP.

TRENDS IN ESTABLISHING SIP

Over the past few years, much attention has been focused on emission regulations for SO_x since these regulations impact the supply of fuel, particularly coal, which can be burned to produce electrical energy. While U.S. supplies of coal are plentiful, some of this coal is too high in S content to be burned in compliance with State and Federal regulations for SO_2 without the use of emission reduction systems, which, in some cases, are either costly or impractical. As a result, many states have been reevaluating their SO_2 regulations to ensure that scarce low-S fuels are being required only in areas where they are needed to protect public health. In some cases, states have revised their S emission regulations to allow the burning of higher S fuels in less polluted areas where they can be burned without violating ambient air quality standards.

EMISSION CONTROL REGULATIONS FOR FOSSIL-FIRED POWER GENERATORS

Units of the Regulation

NSPS contains distinct regulations which limit the emission of particulates and SO_2 from individual fossil-fired boilers as shown below:

	Allowable emission, lb/MBtu heat input	
	Coal-fired unit	Oil-fired unit
Particulate matter	0.1	0.1
SO_2	1.2	0.8

This regulation is applicable to boilers for which construction or modification was begun after August 17, 1971.

In contrast to NSPS regulations, there are variations in (1) the units of measure in which SIP regulations for existing plants are expressed, (2) the equipment (boiler, stack, or entire plant) to which the regulations apply, and (3) the value of the regulation. Table 14 shows the units in which SIP regulations are expressed.

Some states control all emission sources equally, while other states prescribe different emission limits for sources according to the fuel used, the geographic location, the size of the source, or the type of source (e.g., power plant or other combustion units).

TABLE 14. UNITS FOR EXPRESSING STATE SO_2 EMISSION REGULATIONS (26)

1. % S for all fuels
2. % S for each fuel
3. Lb SO_2/MBtu for all fuels
4. Lb SO_2/MBtu for each fuel
5. Lb S/MBtu for all fuels
6. Lb S/MBtu for each fuel
7. Ppm SO_2 in exhaust gas
8. Impact on ambient air quality in ppm
9. Lb SO_2/hr

The most common regulation for controlling SO_2 emissions is by either limiting the amount of S or SO_2 emitted per unit heat input (lb S/MBtu, lb SO_2/MBtu) or limiting the S content of the fuel (% S). However, other SO_2 regulations limit SO_2 emission concentrations expressed as parts of SO_2 per million parts of volume of stack gas (ppm SO_2) or limit the amount of SO_2 emitted per hour (lb SO_2/hr). Some states or regions specify ambient air quality regulations only (i.e., no specific emission limit for a source). Other methods of limiting SO_2 emissions which appear in the SIP include requiring a percent control of input S (% control) and requiring application of "latest reasonably available control technology" or "new proven technologies."

Some of the above-mentioned methods for regulating SO_2 control the emissions of SO_x more directly than do others, and each method has different implications regarding fuels that can be legally burned.

A detailed discussion of the effect of different applications of the SIP regulations on degree of SO_2 removal is included in State Implementation Plan Emission Regulations for Sulfur Oxides: Fuel Combustion (EPA-450/2-76-002, March 1976) (26).

Application of the Regulations

Besides the various units of measure used regulations also vary as to the equipment upon which the emission limit is enforced. Twenty-five states or territories enforce their regulations on a boiler basis, 13 on a stack basis, and 18 on a total plant basis (all boilers collectively). In considering compliance with a regulation, this information determines whether a source is allowed to average its emission over all boilers (or stacks) or if each boiler (or stack) must comply with the regulation.

About one-third of the states regulate specific fuel types. These regulations usually control oil-fired sources more strictly than coal-fired sources since, in general, oil contains less S and has a higher heat content than does coal. But, in some cases, the S restriction for coal is more stringent than the restriction for oil to prohibit the use of coal without flue gas cleaning equipment.

About half of the states have specific SO_2 regulations for various geographic areas within the state. These geographic areas might be specified as cities, counties, Federal Air Quality Control Regions (AQCR), Standard Metropolitan Statistical Areas (SMSA), or some locally defined geographic region. In some areas, including Arizona, New Mexico, and Puerto Rico, regulations have been promulgated which apply to specific plants.

In about one-third of the states, the size of the source determines whether or not the source must comply with an SO_2 emission limitation and if so, the stringency of the limitation. In most cases, source size is defined by the heat input rate measured in MBtu/hr. Other methods of defining source size include lb steam/hr generated and emission potential in tons SO_2/yr emitted. In some states, emission limit is determined by the heat input range under which a source falls. In these states, larger sources usually are controlled more stringently than smaller sources.

Over half of the states use more than one of the parameters discussed above in their regulations. In addition, about 35% of the states have separate regulations for new sources and about 10% have regulations for existing sources that become more stringent over time.

In a few states, the limits on emissions or fuel quality are specified as maximum values averaged over a given time period. Most regulations, however, state that emissions or S content shall not exceed a maximum value. This phraseology implies that instantaneous compliance with the limit is required.

EMISSION COMPLIANCE ALTERNATIVES

Several methods for reducing SO_2 emissions for compliance with State or Federal emission regulations are considered in this study. Alternative strategies considered for power plants include:

Use of low-S coal
Limestone scrubbing with ponding of sludge
Magnesia (MgO) scrubbing with H_2SO_4 production

It is assumed that H_2SO_4 plants and smelters which are out of compliance will reduce their emission by producing H_2SO_4.

The major objectives of this study are to determine the potential for production of byproduct H_2SO_4, in meeting SO_2 emission regulations and the impact of their recovery and sale on S-H_2SO_4 industry supply-distribution characteristics. In all cases, the SO_2 control strategy is selected on the basis of minimum costs for compliance.

CHARACTERISTICS OF THE POWER UTILITY INDUSTRY

In the power industry, either fossil or nuclear fuel is supplied to a boiler and the heat energy of the fuel is used to generate steam. The steam generated in the boilers is fed to steam turbines which drive generators for producing electricity. Fossil fuel is a general term which refers to either coal, oil, or natural gas. Most coal and oil contain S that is emitted as SO_2 in the stack gas when the fuel is burned. Natural gas may contain some S, but in relatively small amounts. Nuclear fuels do not contain S and are not consumed in the same manner as fossil fuels; therefore, their use does not result in the emission of SO_2. In presenting characteristics of the power industry below, emphasis is placed on fossil-fired plants which use coal, oil, or natural gas to generate steam.

Detailed information related to the characteristics of the steam-electric utility industry is found in Steam-Electric Plant Construction Cost and Annual Production Expenses (FPC S-250) (27) and Steam-Electric Plant Air and Water Quality Control Data (FPC S-253) (2). Key information given in these publications is included below to characterize the utility industry.

FOSSIL FUELS

During the decade prior to 1967, approximately 66% of the total annual fossil-fueled power generation was by coal, about 26% by natural gas, and the remaining 8% by residual oil. During the second half of the past decade, when restrictions on the importation of residual oil were removed on the east coast, foreign residual oil began to compete favorably with other fuels. Electric utilities, particularly those near deepwater ports, started to convert from coal to oil and to build new oil-fired units. This process was accelerated with the setting forth of strict SO_2 emission control regulations. With the growing shortage in the supply of natural gas, the use of desulfurized or naturally low-S oil offered the most viable solution to the SO_2 pollution problem along the entire east coast.

A large proportion of the oil used by electric utilities, particularly along the eastern seaboard, is of foreign origin. In the 1965-72 period, approximately 398 coal-fired generating units were converted to the use of oil. Economic considerations dictated the conversions initially. More recently, however, the paramount reason for converting to oil has been the requirement to meet strict S emission regulations which the utilities were unable to do using coal. Most of the conversions took place on the east coast at plants with easy access to ocean and river barge transport of lower priced, desulfurized, or naturally low-S imported residual oil. The Arab oil embargo in late 1973 was instrumental in effecting arbitrary and sudden huge price increases in the world price of oil. In a relatively short period of time, the economic advantage of using imported oil versus coal as a fuel for electric power generation reversed. In early 1974 a number of utilities on the east coast reported 42 oil-burning plants of their systems capacities as having capability of conversion from oil to coal. A few of these plants have been converted to coal, with conversion by the others contingent upon coal availability. Due to current uncertainties in the long-range oil supply picture, and the increasing amounts of nuclear generation becoming available to electric utilities, oil's role in electric generation will probably decline in the future.

Historical Consumption and Characteristics

The historical consumption pattern of coal, natural gas, and oil in the U.S. from 1969 through 1973 based on FPC Form 67 data is shown in Table 15. Historical characteristics of coal, oil, and gas for the corresponding period are given in Table 16. The data indicate that the average heating value of coal, fuel oil, and gas has declined slightly during this period. The data also show a slight decline in the average S content of coal and a significant decline in the average S content of oil. The lower heating values of coal and fuel oil appear to be at the expense of using fuels with lower S contents. The average ash content of coal during the same period increased from approximately 12.5 to 13.3%.

TABLE 15. CONSUMPTION PATTERN OF FOSSIL FUELS

IN THE U.S., 1969-73 (2)

	Total Btu, 10^{15}				% of total Btu		
Year	Coal	Oil	Gas	Total	Coal	Oil	Gas
1969	7.065	1.577	3.429	12.071	58.5	13.1	28.4
1970	7.098	2.008	3.820	12.926	54.9	15.5	29.6
1971	7.244	2.328	3.841	13.413	54.0	17.4	28.6
1972	7.794	2.816	3.811	14.421	53.9	19.6	26.5
1973	8.583	3.270	3.517	15.370	55.8	21.3	22.9

TABLE 16. HISTORICAL FOSSIL FUEL CHARACTERISTICS FOR THE PERIOD 1969-73 (2)

	Year				
	1969	1970	1971	1972	1973
Coal					
Average heating value, Btu/lb	11,628	11,276	11,169	11,176	11,090
Average S content, % by wt	2.59	2.58	2.47	2.39	2.32
Equivalent SO_2 content, lb SO_2/MBtu	4.46	4.58	4.42	4.28	4.27
Average ash content, % by wt	12.53	13.72	13.85	13.41	13.29
Fuel Oil					
Average heating value, Btu/gal	148,727	147,991	147,017	146,285	145,772
Average S content, % by wt	1.68	1.52	1.28	1.07	0.98
Equivalent SO_2 content, lb SO_2/MBtu	1.80	1.64	1.40	1.18	1.08
Gas					
Average heating value, Btu/ft^3	1,033	1,031	1,030	1,028	1,028

Projected 1978 Consumption and Characteristics

In 1973 utilities were also requested by FPC to project fuel consumption and characteristics for 1978. The majority of utilities provided FPC with these projections. For the utilities which did not project this information, fuel consumption and characteristics were assumed to be the same as that reported for 1973. Based on the updated projections, Table 17 shows the consumption rates and characteristics of fossil fuels projected to be utilized during 1978. For plants which use multiple fuels and did not project their 1978 consumption, the method for projecting fuel is discussed in Appendix J.

A comparison of the total projected 1978 coal, fuel oil, and gas consumption with the historical 1973 fuel consumption by region is shown in Table 18. Figure 10 shows the overall trend in fossil fuel consumption from 1969 through 1978. The projections indicate a general increase in the consumption of coal and oil, but a slight decrease in the consumption of gas. The regional increases or decreases are primarily influenced by fuel availability and price. In reviewing the data, it must be remembered that a significant amount of new generating capacity between 1973 and 1978 is from nuclear units. The data shown include the effect of projected decreases in fossil fuel utilization as a result of new nuclear units coming online as well as changes in fossil fuel consumption resulting from decreases in fuel availability or increases in cost.

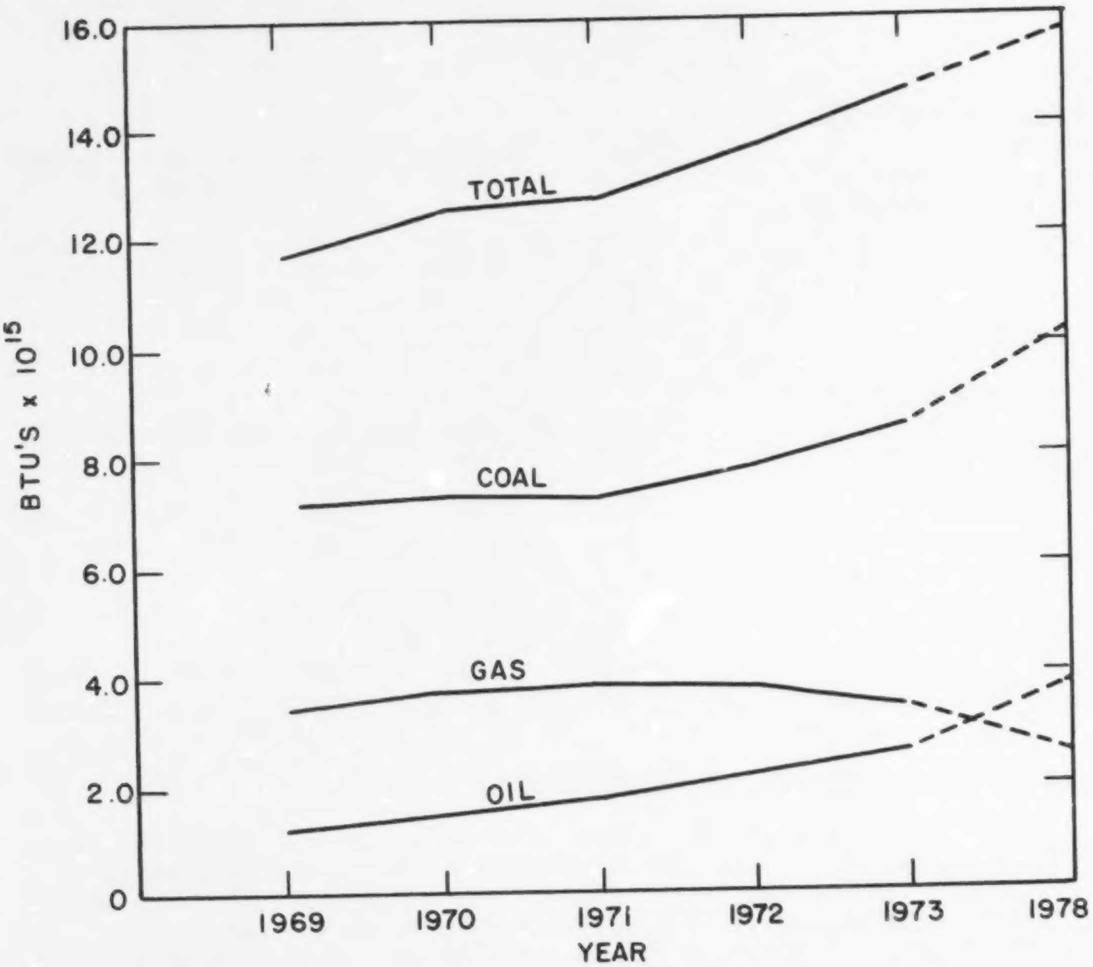

Figure 10. Trends in the consumption of coal, oil, and gas from 1969-78.

TABLE 17. PROJECTED 1978 FOSSIL FUEL CONSUMPTION RATES AND CHARACTERISTICS

	All plants	Plants out of compliance
Coal		
Total consumption		
ktons	475,570	226,780
GBtu	10,408,290	5,125,075
Heating value, Btu/lb	10,943	11,300
S content, % by wt	2.12	2.81
Equivalent SO_2 content, lb SO_2/MBtu	3.87	4.97
Oil		
Total consumption		
kbbl	620,247	110,167
GBtu	3,827,427	686,900
Heating value, Btu/gal	146,924	148,454
S content, % by wt	0.99	1.42
Equivalent SO_2 content, lb SO_2/MBtu	1.08	1.54
Gas		
Total consumption		
Mft^3	2,556,021	108,239
GBtu	2,602,232	116,968
Heating value, Btu/ft^3	1,018	1,081

POWER PLANT CHARACTERISTICS

Plant Location

The location of major coal-, oil-, and gas-fired power plants based on 1973 FPC data is shown in Figures 11 through 13 respectively. Figure 14 shows the location of plants which use multiple fuel mixes for the same period. The data show coal-fired plants to be scattered from the east to the west coast. The highest concentration of coal-fired plants is in the Midwest. Oil-fired power plants are most predominant along the east and west coasts and the lower Mississippi Valley; however, they are also found at other scattered locations in the Midwestern States. Gas-fired plants are predominant near the Louisiana and Texas Gulf Coast and adjacent states, but like oil-fired plants, are also found at other locations. At the end of 1973, plants with facilities for using multiple fuels were widely scattered.

Plant Size

Historical data for conventional fossil-fueled steam-electric generating plants for the total power industry are shown in Table 19. An analysis of these data indicates that total fossil-fueled power generation has generally doubled every 10 yr. New plants are constructed to (1) provide additional capacity for the increasing electrical demand and (2) provide replacement capacity for older less-efficient plants which are being retired. The total

TABLE 18. COMPARISON OF PROJECTED 1978 REGIONAL FOSSIL FUEL CONSUMPTION WITH HISTORICAL 1973 CONSUMPTION

Geographic region[a]	Coal, ktons	Oil, kbbl	Gas, Mft^3
Historical 1973 consumption (2)			
New England	1,080	82,930	6,070
Middle Atlantic	46,990	144,690	64,730
East North Central	135,960	23,340	105,590
West North Central	31,620	3,440	352,820
South Atlantic	75,860	141,380	202,660
East South Central	63,060	6,510	73,750
West South Central	4,730	20,850	1,957,070
Mountain	23,930	8,990	207,630
Pacific	3,740	76,970	451,220
U.S. total	386,970	509,100	3,421,540
Projected 1978 consumption[b]			
U.S. total	475,570	620,250	2,556,020

a. The states included in each geographic region are: New England - Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont; Middle Atlantic - New Jersey, New York, Pennsylvania; East North Central - Illinois, Indiana, Michigan, Ohio, Wisconsin; West North Central - Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota; South Atlantic - Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia; East South Central - Alabama, Kentucky, Mississippi, Tennessee; West South Central - Arkansas, Louisiana, Oklahoma, Texas; Mountain - Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming; Pacific - California, Oregon, Washington.

b. Regional consumption data not available.

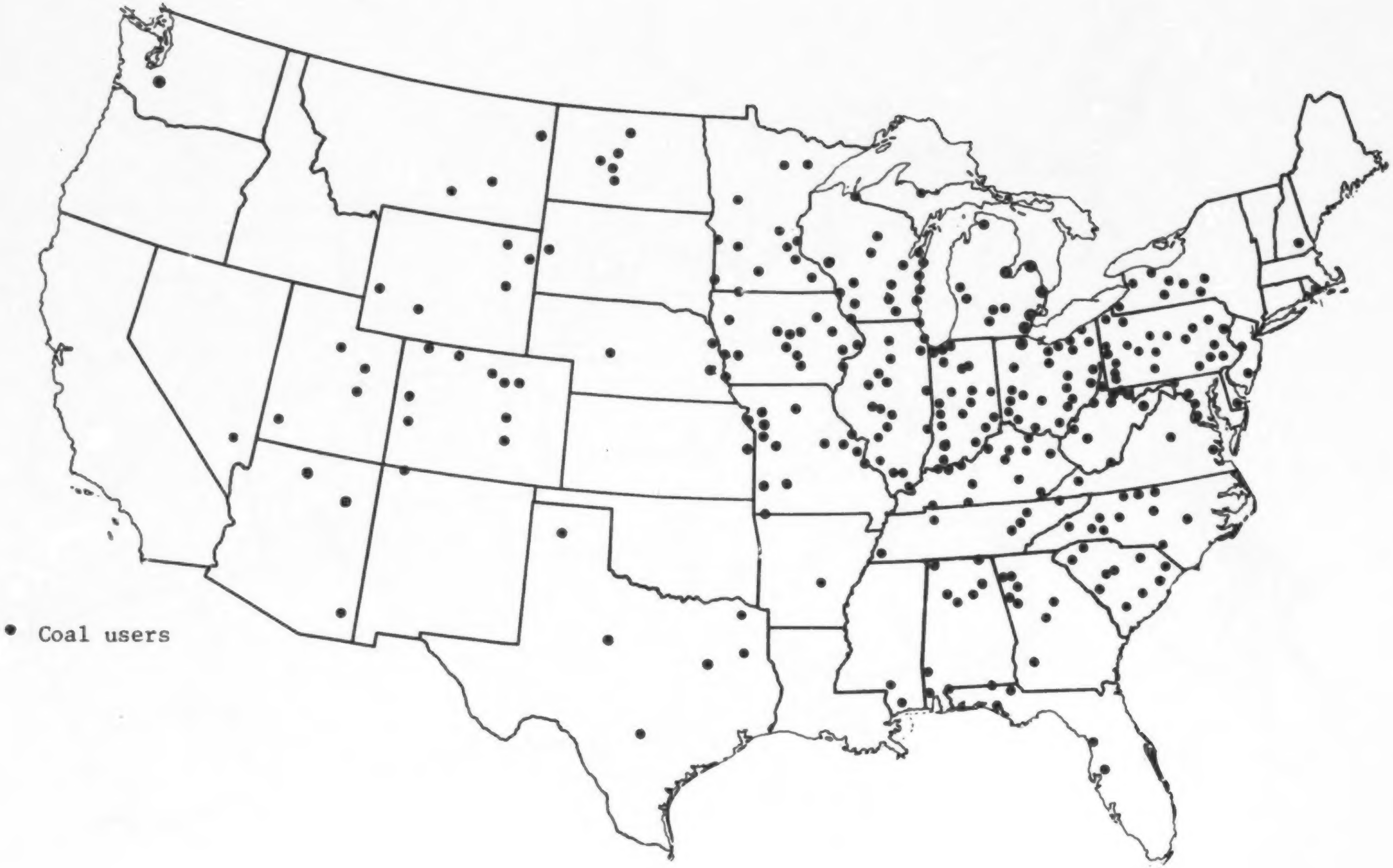

Figure 11. Location of coal-fired steam-electric power plants (1978).

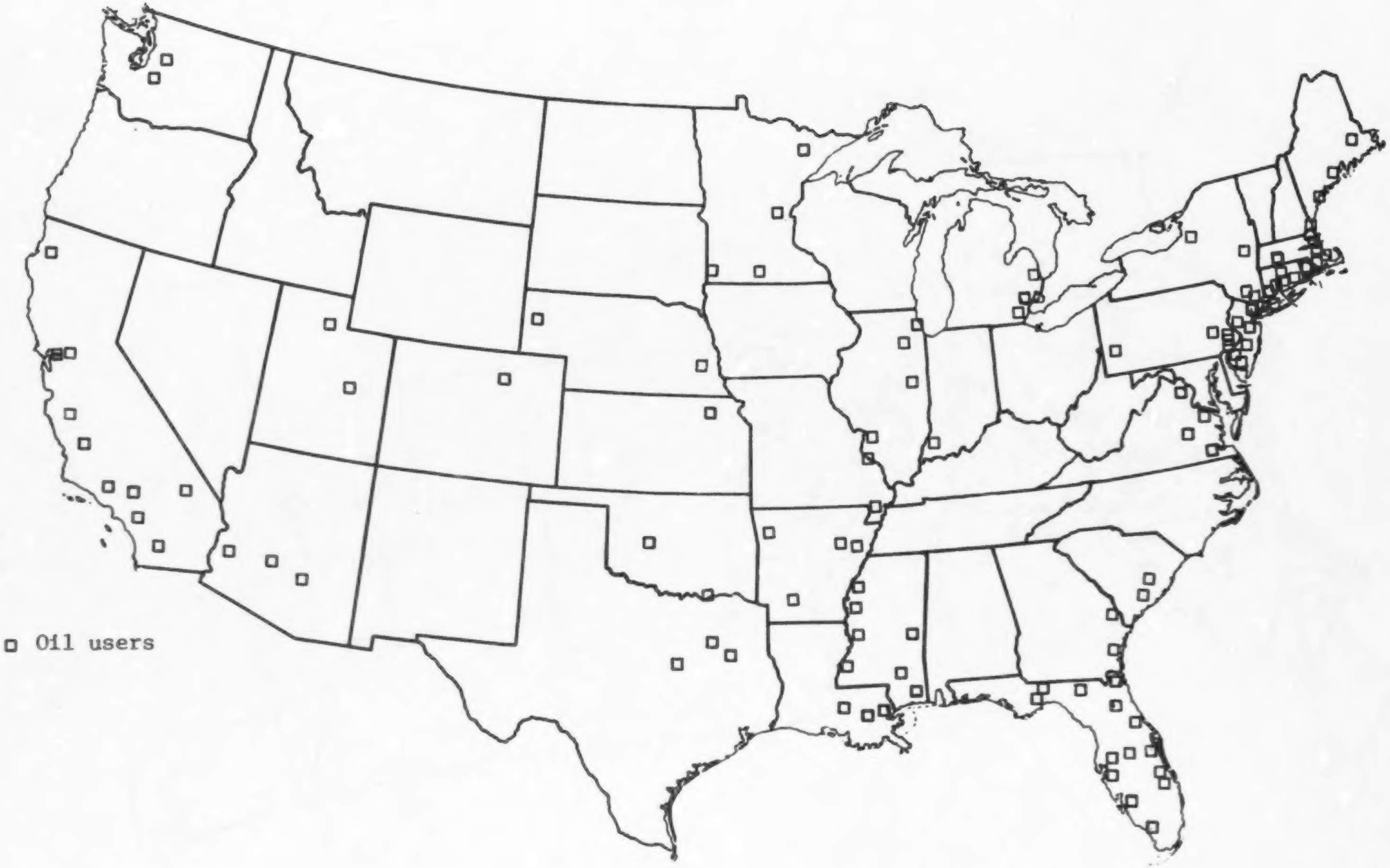

Figure 12. Location of oil-fired steam-electric power plants (1978).

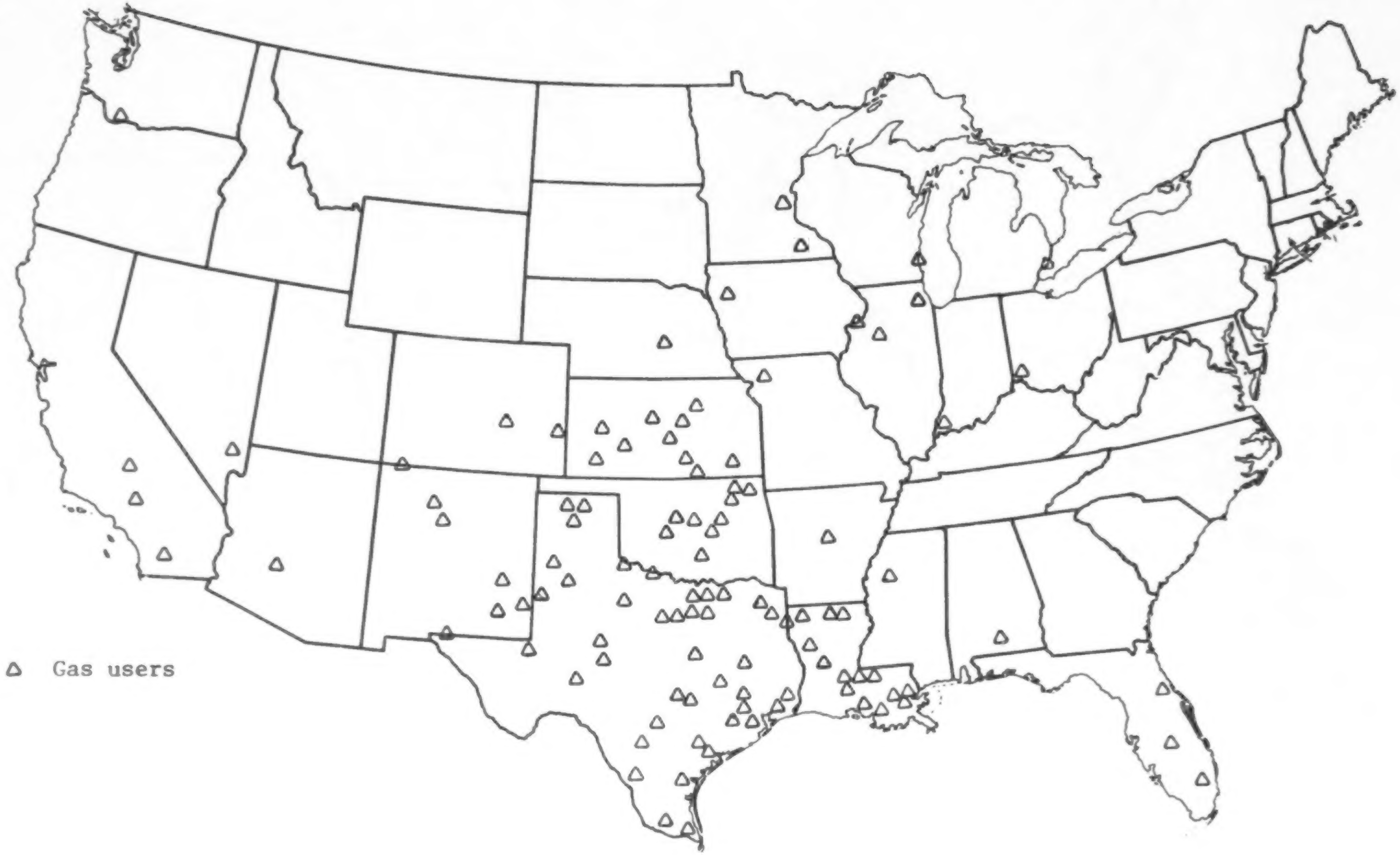

Figure 13. Location of gas-fired steam-electric power plants (1978).

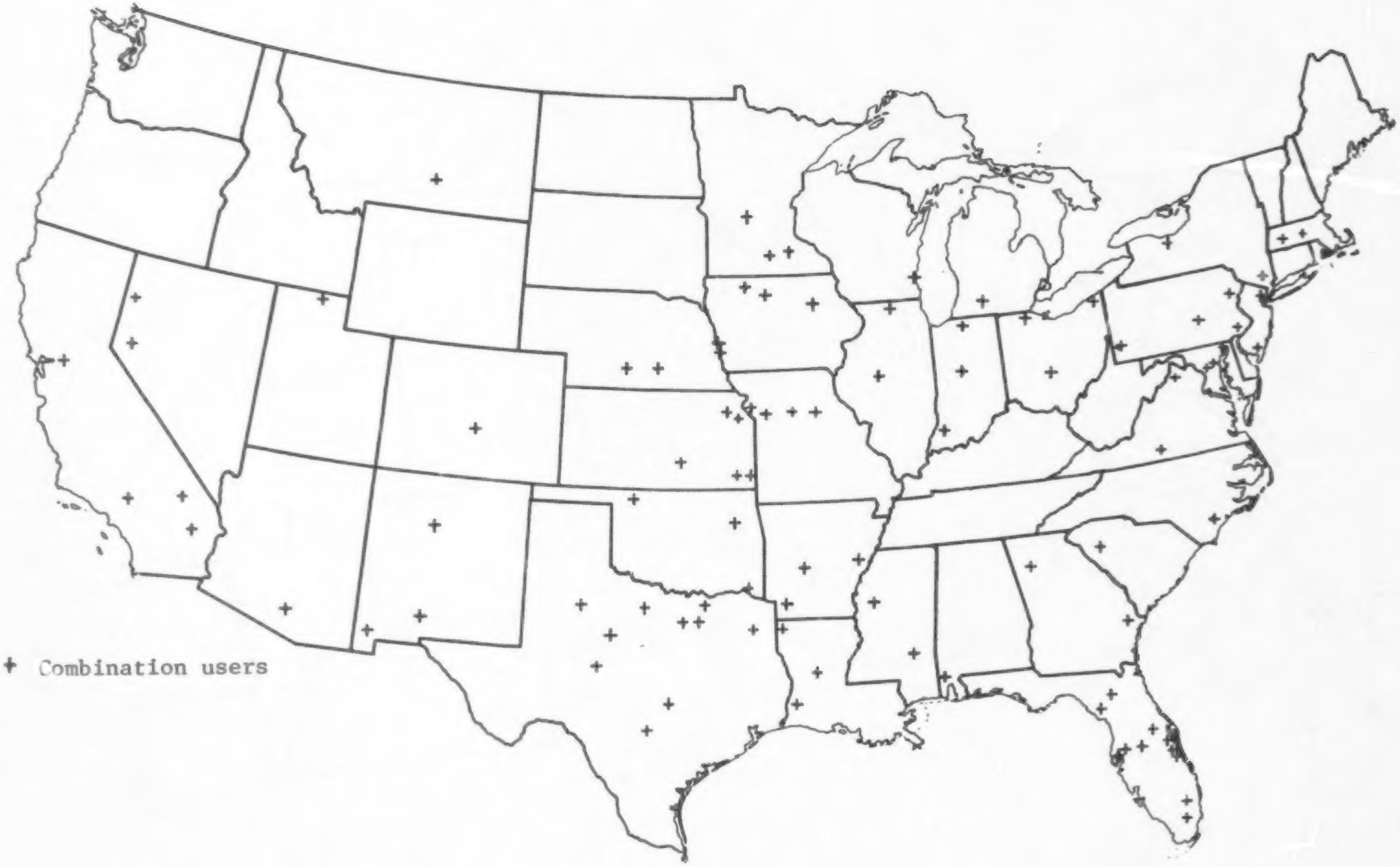
+ Combination users

Figure 14. Location of steam-electric power plants capable of utilizing a combination of fossil fuels.

installed steam-electric generating capacity from fossil-fueled plants increased from 26,000 MW in 1938 to over 318,000 MW in 1973. During the same period, average plant size in megawatts increased from 22 to 322. The total number of plants varies annually as new plants are built and old plants are retired. At the end of 1973, there were 219 fossil-fueled plants 500 MW in size or larger.

TABLE 19. CONVENTIONAL FOSSIL-FUELED STEAM-ELECTRIC GENERATING PLANTS, TOTAL AND AVERAGE CAPACITIES, NET GENERATION AND CAPACITY FACTORS FOR THE TOTAL POWER INDUSTRY, 1938-73[a,b] (27)

	1938	1947	1957	1967	1971	1972	1973
Number of plants	1,165	1,045	1,039	971	985	979	988
Installed capacity, MW	26,066	36,035	99,500	210,237	275,593	294,049	318,357
Average plant size, MW	22	35	96	217	280	300	322
Net generation, GkWh	68.4	174.5	497.2	974.1	1,282.2	1,378.3	1,459.2
Approximate average annual plant factor, %	35	55	57	53	53	54	52

a. Excludes Puerto Rico.
b. Excludes nuclear, geothermal, gas turbine, and internal combustion plants.

Most power plants consist of a number of separate units which are capable of producing power independently of the other units within the plant. Each unit generally includes a separate boiler for generating steam, a separate turbine and generator for producing electricity, and separate flue gas handling facilities. Although some plants have common flue gas stacks for multiple boilers, most boilers are designed with separate stacks. Modular units allow for servicing and maintenance without significantly affecting the output of the overall plant and allows for the addition of new generating capacity without intefering with the operation of the existing facilities.

A diagram showing the general layout of a plant, including facilities for SO_2 control, is shown in Figure 15. This diagram illustrates the relationships between plant, boilers, and stacks, and facilities for controlling SO_2 emissions.

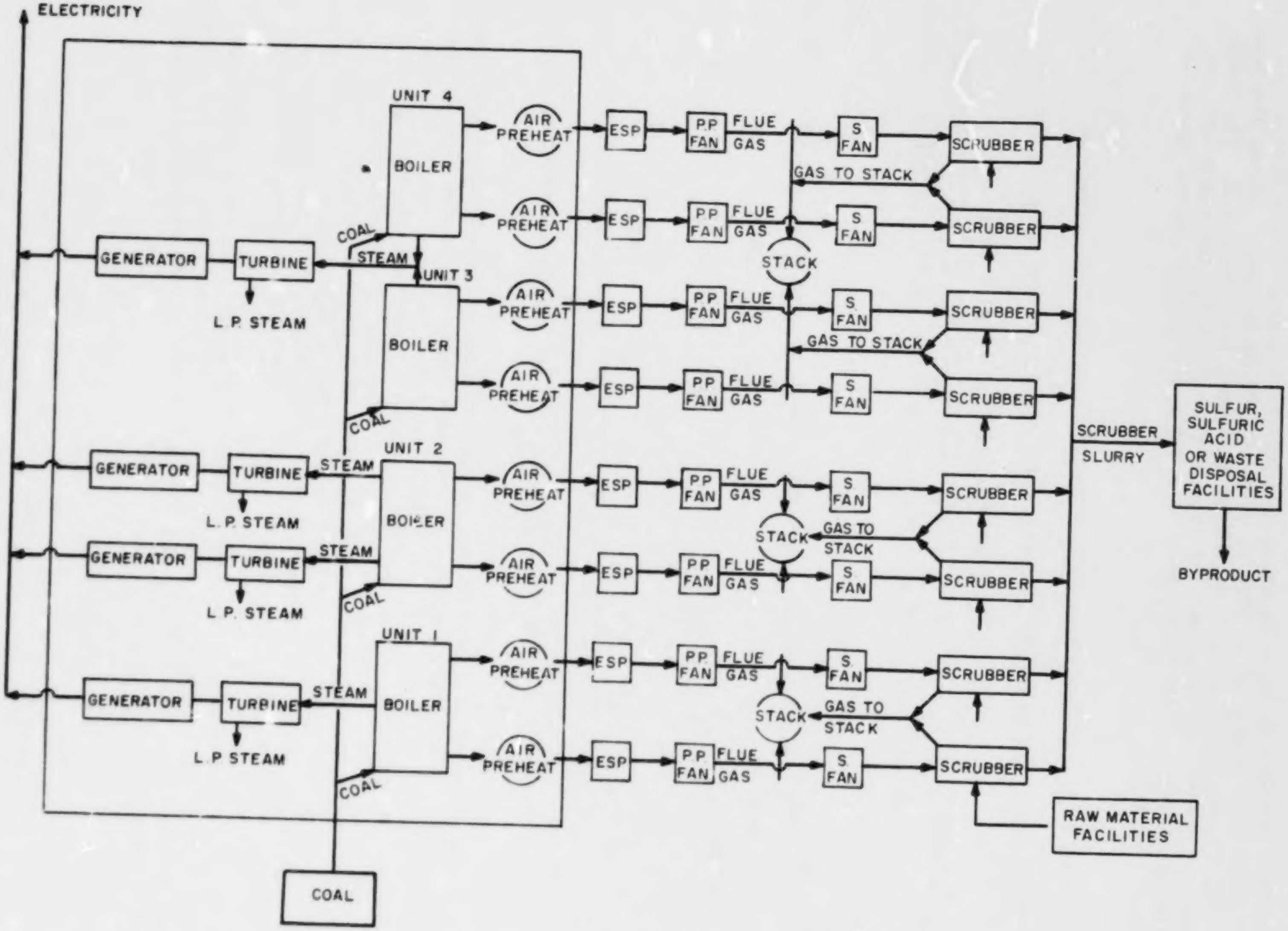
ELECTRICITY
UNIT 4
UNIT 3
UNIT 2
UNIT 1
BOILER
COAL
STEAM
GENERATOR
TURBINE
L. P. STEAM
AIR PREHEAT
ESP
P.P. FAN
FLUE GAS
STACK
GAS TO STACK
S. FAN
SCRUBBER
SCRUBBER SLURRY
SULFUR, SULFURIC ACID OR WASTE DISPOSAL FACILITIES
BYPRODUCT
RAW MATERIAL FACILITIES
COAL

Figure 15. General layout of a power plant designed with an FGD system.

BOILER CHARACTERISTICS

Boiler Size

As an illustration of the size relationship between plants and boilers, Table 20 identifies the total plant size in megawatts and the number of separate units for the 15 largest steam-electric plants in the U.S. based on 1973 FPC data. These plants range in size from 1872-2933 MW. For comparison, individual boiler sizes at these plants range from 69-1300 MW.

TABLE 20. FIFTEEN LARGEST STEAM-ELECTRIC PLANTS IN THE U.S. IN 1973[a] (27)

Plant name	MW[b]	Unit	Utility
Amos	2,933	3	Appalachian Power Company
Paradise	2,558	3	Tennessee Valley Authority
Labadie	2,482	4	Union Electric Company
Monroe	2,462	3	Detroit Edison Company
Sammis	2,456	7	Ohio Edison Company
Robinson, P.H.	2,315	4	Houston Lighting and Power Company
Four Corners	2,270	5	Arizona Public Service Company
Moss Landing	2,175	7	Pacific Gas and Electric Company
Alamitos	2,121	6	Southern California Edison Company
Pittsburg	2,029	7	Pacific Gas and Electric Company
Marshall	2,000	4	Duke Power Company
Widows Creek	1,978	8	Tennessee Valley Authority
Nine Mile Point	1,917	5	Louisiana Power and Light Company
St. Clair	1,905	7	Detroit Edison Company
Keystone	1,872	2	Pennsylvania Power and Light Company

a. Coal-fired except as noted.

b. Based on maximum generator ratings.

The average size of larger boilers (>300 MW) placed in service has generally increased over the years. Table 21 shows the number of units, corresponding total megawatts, and the average unit size in megawatts for units placed in service during the period 1959-73.

TABLE 21. TRENDS IN BOILER SIZE, 1959-73 (27)

	Fossil-fueled units, 300 MW and larger		
Year	No. units placed in service	Total MW	Average unit size, MW
1959	5	1,800	360
1960	8	2,525	317
1961	9	3,180	353
1962	7	2,525	361
1963	10	4,500	450
1964	10	3,625	362
1965	17	7,740	455
1966	20[a]	8,424	421
1967	26	13,245	509
1968	22	12,274	558
1969	26	14,249	548
1970	25	14,413	577
1971	29	17,575	606
1972	32	18,753	586
1973	35	21,843	624
Total	281	146,671	522

a. Seven of these units were actually installed in prior years and were rerated in 1966.

For comparison with the size ranges given above, the average boiler size considering all boilers projected to be operational in 1978 is 122 MW and the average boiler size for plants which are projected to be out of compliance in 1978 is 159 MW. In contrast, the largest commercial boilers presently in operation or under construction are 1300-MW units.

Boiler Capacity Factors

The data given in Table 19 indicate that average annual capacity factors for power plants ranged from approximately 52-57% of rated capacity for the period 1947-73. In contrast, however, capacity factors for individual boilers within a plant vary considerably. As new units are added, load factors for the older units are generally decreased and the newer, more efficient units are operated at higher capacity factors. However, delays in construction of new generating capacity often require older plants to operate at higher than normal capacity factors. Based on historical FPC data for 1969-73, the average annual capacity factors for all boilers as a function of boiler age were determined and are shown in Figure 16. The data indicate a gradual increase in capacity factors from approximately 50 to 65% during the first 10 yr of operation followed by a relatively constant profile for approximately 5-7 yr and a gradually declining operating profile over the remaining life of the plant. Boilers >20 yr old generally operate at annual capacity factors <50%. A breakdown of the projected 1978 distribution of all boilers by age and capacity factor is shown in Table 22. Table 23 shows the distribution for these boilers projected to be out of compliance.

TABLE 22. DISTRIBUTION OF BOILERS BY AGE AND CAPACITY FACTOR - ALL BOILERS

	Number of boilers and (% of total number of boilers)				
	Boiler capacity factor				
Boiler age, yr	<20%	20-40%	41-60%	>60%	Total
0-5	28 (0.8%)	26 (0.8%)	84 (2.5%)	40 (1.2%)	178 (5.3%)
6-10	30 (0.9%)	34 (1.0%)	92 (2.7%)	127 (3.8%)	283 (8.4%)
11-15	20 (0.6%)	45 (1.3%)	73 (2.2%)	120 (3.5%)	258 (7.6%)
16-30	265 (7.9%)	410 (12.1%)	465 (13.7%)	274 (8.1%)	1,414 (41.8%)
>30	1,009 (29.8%)	154 (4.6%)	61 (1.8%)	25 (0.7%)	1,249 (36.9%)
Total	1,352 (40.0%)	669 (19.8%)	775 (22.9%)	586 (17.3%)	3,382 (100%)

Boiler capacity factors also vary as a function of boiler size. Larger boilers are often operated as base load plants while the older, generally smaller and less-efficient boilers are operated to provide peaking capacity. Table 24 shows a breakdown of the projected 1978 distribution of all boilers by size and capacity factor. Table 25 shows the distribution for these boilers projected to be out of compliance.

Capacity factors are also a function of fuel type; however, plant design is the primary consideration which affects the consumption-distribution pattern. For plants which are capable of burning alternate fuels, the utilization trend changes as a function of fuel availability and costs.

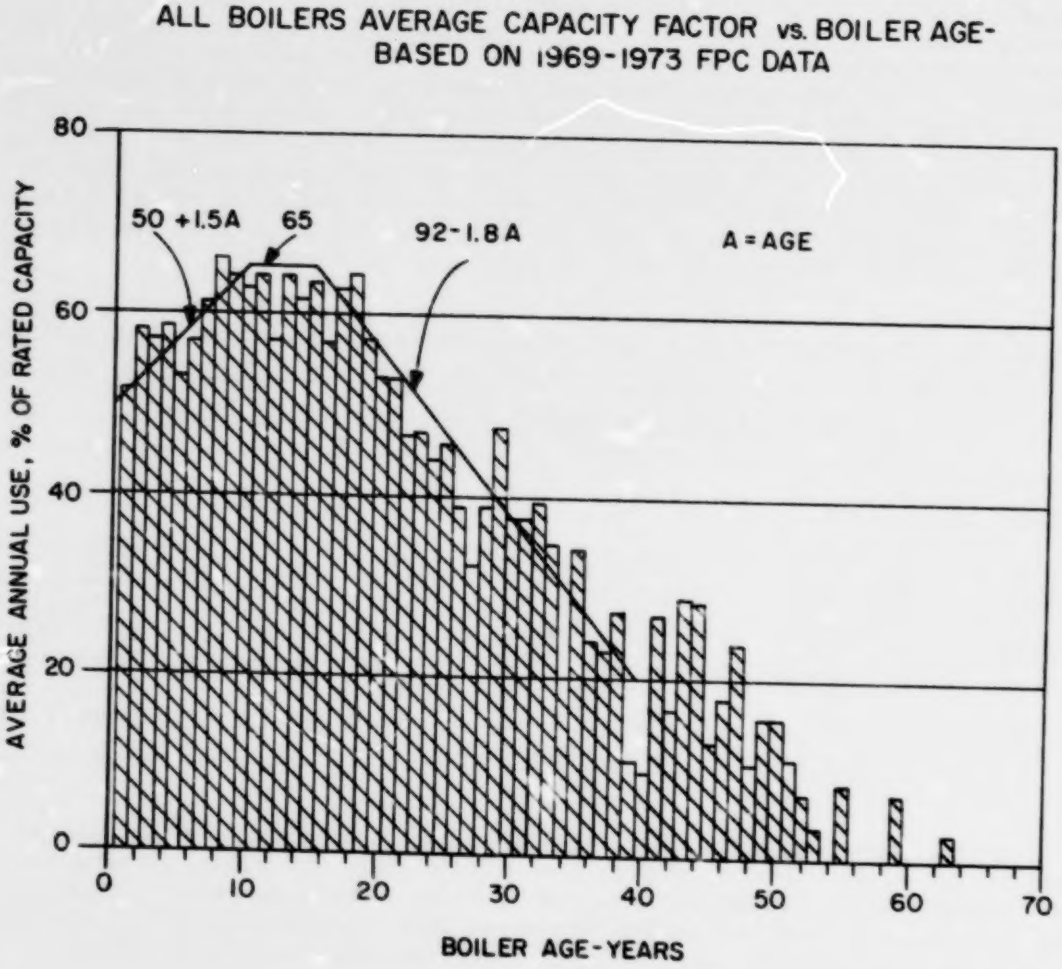

Figure 16. Average boiler capacity factors as a function of boiler age.

TABLE 23. DISTRIBUTION OF BOILERS BY AGE AND CAPACITY FACTOR -

BOILERS OUT OF COMPLIANCE

Boiler age, yr	Number of boilers and (% of total number of boilers)				
	Boiler capacity factor				
	<20%	20-40%	41-60%	>60%	Total
0-5	5 (0.6%)	8 (1.0%)	49 (5.9%)	19 (2.3%)	81 (9.8%)
6-10	9 (1.1%)	5 (0.6%)	26 (3.1%)	45 (5.4%)	85 (10.2%)
11-15	4 (0.5%)	5 (0.6%)	16 (1.9%)	26 (3.1%)	51 (6.1%)
16-30	56 (6.7%)	90 (10.8%)	135 (16.2%)	66 (7.9%)	347 (41.6%)
>30	216 (25.9%)	38 (4.6%)	13 (1.6%)	2 (0.2%)	269 (32.3%)
Total	290 (34.8%)	146 (17.6%)	239 (28.7%)	158 (18.9%)	833 (100%)

TABLE 24. DISTRIBUTION OF BOILERS BY SIZE AND CAPACITY FACTOR -

ALL BOILERS

Boiler size, MW	Number of boilers and (% of total number of boilers)				
	Boiler capacity factor				
	<20%	20-40%	41-60%	>60%	Total
<200	1,270 (37.6%)	601 (17.8%)	510 (15.1%)	390 (11.5%)	2,771 (82.0%)
200-500	53 (1.6%)	45 (1.3%)	180 (5.3%)	120 (3.5%)	398 (11.7%)
501-1000	29 (0.8%)	21 (0.6%)	79 (2.3%)	76 (2.3%)	205 (6.1%)
>1000	0 (0.0%)	2 (0.1%)	6 (0.2%)	0 (0.0%)	8 (0.2%)
Total	1,352 (40.0%)	669 (19.8%)	775 (22.9%)	586 (17.3%)	3,382 (100%)

TABLE 25. DISTRIBUTION OF BOILERS BY SIZE AND CAPACITY FACTOR - BOILERS OUT OF COMPLIANCE

Boiler size, MW	Number of boilers and (% of total number of boilers)				
	Boiler capacity factor				
	<20%	20-40%	41-60%	>60%	Total
<200	283 (34.0%)	129 (15.5%)	129 (15.5%)	87 (10.4%)	628 (75.4%)
200-500	7 (0.8%)	12 (1.4%)	69 (8.3%)	38 (4.6%)	126 (15.1%)
501-1000	0 (0.0%)	5 (0.6%)	36 (4.3%)	33 (4.0%)	74 (8.9%)
>1000	0 (0.0%)	0 (0.0%)	5 (0.6%)	0 (0.0%)	5 (0.6%)
Total	290 (34.8%)	146 (17.5%)	239 (28.7%)	158 (19.0%)	833 (100%)

Boiler Heat Rates

Because heating values of fossil fuels vary over a wide range, the thermal efficiency of fossil fuel steam-electric power plants is generally expressed in terms of heat rate. Heat rate is defined as the total Btu of heat required to generate 1 kWh of electricity for delivery to the transmission system. These data are reported annually to FPC at the utility, plant, and boiler level. Table 26 shows historical national average heat rates for fossil-fueled power plants from 1938-73. This table also shows the thermal efficiency for converting heat energy into electricity, which is calculated by dividing the thermal equivalent of 1 kWh (3413 Btu) by the heat rate. As shown, national average heat rates have declined from a high of 16,500 Btu/kWh in 1938 to about 10,400 Btu/kWh in 1972-73.

According to the FPC data, there were 14 units in 1973 with heat rates of <9000 Btu/kWh compared with 18 units in 1972. The most efficient single unit had a heat rate of 8714 Btu/kWh in 1973. Corresponding to 1973, there was a total of 41 plants with overall heat rates of <9,500 Btu/kWh, and 124 plants with heat rates under 10,000 Btu/kWh. These totals account for 19 and 45% of the total electrical generation respectively. The most efficient single plant had an average heat rate of 8818 Btu/kWh. Based on projections to 1978, plant heat rates range from 8,818 to >30,000 Btu/kWh.

The most efficient heat rate at the company level was reported as 9524 Btu/kWh. In 1973 there was a total of 16 utilities with heat rates <10,000 Btu/kWh.

TABLE 26. NATIONAL AVERAGE HEAT RATES FOR FOSSIL-FUELED STEAM-ELECTRIC PLANTS - TOTAL ELECTRIC POWER INDUSTRY, 1938-73 (27)

Year	Btu/net kWh	Thermal efficiency,[a] %	Year	Btu/net kWh	Thermal efficiency,[a] %
1938	16,500	20.68	1962	10,558	32.33
1948	15,738	21.69	1963	10,482	32.56
1952	13,361	25.54	1964	10,462	32.62
1953	12,889	26.48	1965	10,453	32.65
1954	12,180	28.02	1966	10,415	32.77
1955	11,699	29.17	1967	10,432	32.72
1956	11,456	29.79	1968	10,398	32.82
1957	11,365	30.03	1969	10,447	32.67
1958	11,085	30.79	1970	10,494	32.52
1959	10,970	31.11	1971	10,478	32.57
1960	10,760	31.72	1972	10,379	32.88
1961	10,650	32.05	1973	10,389	32.85

a. Based on 3,413 Btu as the energy equivalent of 1 kWh.

SCRUBBING COST GENERATOR

Each utility is required by law to report annually plant, boiler, and fuel characteristics for their steam-electric generators on FPC Form 67. A file containing FPC Form 67 data for the period 1969-73 was supplied to TVA along with utility projections, where available, of similar data for 1978 for use in the byproduct marketing study. The data were primarily for use in projecting SO_2 emissions at power plants for determining the compliance status of power plants with State and Federal SO_2 emission regulations and the market potential for S and H_2SO_4 abatement production at plants which are out of compliance.

TVA developed a procedure for using the Form 67 data in conjunction with applicable SO_2 emission regulations to (1) project the compliance status of individual plants and the quantity of S which must be recovered to meet SO_2 emission regulations for those plants out of compliance, (2) estimate costs for removing the required amount of SO_2 from the gas to meet compliance requirements by three alternative scrubbing processes, and (3) compare the costs for scrubbing including credit from sale of byproducts with alternative costs for complying with the regulation by the use of low-S coal. The overall comparison is used to assist in selecting the minimum cost compliance alternative. Discussions of the data required for input to the scrubbing cost generator and the method for developing the model are given below.

PROCEDURE FOR UTILIZING FPC DATA TO ESTIMATE COMPLIANCE STATUS

FPC Form 67 Data Projections

The projected 1978 FPC Form 67 data which serve as input to both the SO_2 emission and compliance model and the scrubber cost generator include a number of key data items which were reported to FPC at the plant level only. In the compliance tests and the scrubber cost generator the majority of the calculations are begun at the boiler level; therefore, it was necessary to project much of the plant level data to the boiler level for input to these models. Plant level data available from either 1978 projections or historical 1969-73 data updated with more current information from FPC include plant capacity in megawatts, overall projected plant capacity factor, fuel consumption breakdown as coal, oil, and gas, plant heat rate in Btu/kWh, heating values of coal, oil, and gas, and S contents of coal and oil. At the boiler level, the following data are available from similar sources: boiler startup year, boiler capacity in megawatts, and design combustion air rates to the boiler at full load expressed in sft^3/min. Fuel is allocated from the plant level to the boiler level from either utility projections for 1978 or historical 1969-73 consumption. For the cases in which utilities projected plant level data, the data

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were generally used as projected. For the other cases where historical plant data were used projections at the boiler level were adjusted in accordance with the historical boiler age-capacity factor relationship which was described earlier. In all cases, data projections and adjustments at the boiler level are allowed to override the plant level data. Details of the methods for allocating fuel from the plant to the boiler level may be found in Appendix J. The projections of fuel consumptions are reported in terms of GBtu/yr for each fuel at each boiler for convenience in comparing the relative fuel distribution, and individual boiler capacity factors (annual) are calculated.

Since individual boiler heat rates are not included in the FPC data file, the overall plant heat rates were assumed to be applicable for each boiler in the plant. Reported air rates to the boiler are compared with calculated air rates as a check of the data file. If reported air rates differ from calculated rates by >25%, calculated air rates are allowed to override the reported rates.

The FPC data file is used by the compliance test model to project SO_2 emissions for each boiler and plant for comparison with allowable emissions. The compliance test procedure is discussed below.

Compliance Test

The SO_2 emission and compliance model uses the projected annual fuel consumption and characteristics data to calculate the annual quantity of S which is emitted for each boiler and plant. For each plant, allowable emissions are calculated based on NSPS for new boilers or the applicable SIP in effect for AQCR in which the plant is located for existing boilers in conjunction with the heating value and S content of the fuel. Excess emissions expressed as tons S which must be removed per year are then estimated as the difference between the calculated and allowable emissions. In the test for compliance, the plant is considered to be in compliance with the regulation if actual emissions are less than allowable emissions, or do not exceed allowable emissions by >10%. This allowance factor is applied to adjust for round off differences in converting SIP from the various units of expression to the equivalent single unit of expression (lb SO_2/MBtu) for simplification in testing for compliance.

The compliance procedure tests the level of application of the SIP to determine the procedure for complying with the regulation. Levels of application are specified as either (1) an entire plant, (2) an individual boiler, or (3) an individual stack. In all cases where scrubbers are required, they are assumed to be designed for an SO_2 removal efficiency of 90%. However, the actual performance level needs to be more clearly defined in sustained full-scale operation when high-S coal is burned. The 90% level results in overcompliance for many plants, particularly those which have SIP which apply at the boiler level.

Compliance Procedure for Meeting Plant Level SIP--

When the regulation applies to an entire plant, the model determines the number of boilers which must be scrubbed, ordered from lowest to highest cost, to reduce overall plant emission to comply with the regulation. The FPC data for these plants and specific boilers are used as input to the scrubbing cost generator for projecting costs.

Compliance Procedure for Meeting Boiler Level SIP--

When SIP are applied at the boiler level, the compliance test procedure determines compliance status for individual boilers similar to the method for determining compliance status at the plant level and specifies the boilers which exceed allowable emissions. The FPC data for these plants and specific boilers are then used as input to the scrubbing cost generator and for projecting costs similar to the plant level SIP compliance procedure. A hypothetical example is given below to illustrate the difference in SO_2 emission reductions when the two procedures are applied to the same plant. Assume that a plant made up of four equal-size boilers operating at equal capacity factors has a total annual S emission rate of 120,000 tons/yr and an allowable emission of 60,000 tons/yr. Excess emissions for this plant calculated by difference are equal to 60,000 tons/yr. The total S emission rate per boiler is about 30,000 tons/yr. If scrubbers capable of removing 90% of the S to the boiler were installed on each boiler, the net reduction in emissions for each boiler would be 0.90 x 30,000 or 27,000 tons/yr. If the SO_2 emission regulation was a plant level regulation, the reduction in emissions could be achieved by installing scrubbers on three of the four boilers. (Excess emissions = 60,000 tons/yr; reduction in emissions for three boilers = 3 x 27,000 or 81,000 tons/yr, which is greater than the quantity of excess emissions.) If the same hypothetical plant had boiler level rather than plant level SIP, the fourth boiler would not be in compliance, even though the total emissions for the plant were less than the allowable emissions. Therefore, all four boilers would require scrubbers if the regulation was on a boiler basis.

Compliance Procedure for Meeting Stack Level SIP--

Power plants are designed with a wide variety of boiler-stack configurations. Therefore, the application of stack level regulations has different implications as far as the procedure for complying with the regulation. If, for example, the plant is designed with multiple boilers, but with a single stack, the procedure for meeting the regulation is similar to the procedure for complying with plant level regulations. If the plant is designed with separate stacks for each individual boiler, the procedure for meeting the regulations is similar to the procedure for complying with boiler level SIP. Most power plants fit into one of the above two categories. However, there are a number of plants which have multiple boilers which feed to more than one stack. In many cases, the FPC data for these plants do not include sufficient information to determine the specific association between stacks and boilers. Therefore it is not possible for these plants to use a compliance test to determine status of individual stacks. Because of this problem, and with the concurrence of EPA, all stack level SIP are used similar to boiler level SIP when the association between boilers and stacks cannot be determined.

The final output of the scrubbing cost generator is an identification of all boilers at each plant that must be scrubbed to meet the SO_2 emission regulation.

Compliance Status of Power Plants

Based on the projected data, it is estimated that a total of 187 plants will be out of compliance with either NSPS (new plants) or SIP (existing plants) in 1978. It should be noted that many of the plants shown as out of compliance are likely on a compliance schedule with technology that may be different from that projected. Of these, a total of 69 plants is out of compliance based on plant level SIP and 118 based on boiler level SIP. A map showing the location of these plants is shown in Figure 17. Boiler sizes for plants out of compliance range from as low as 5 to 1150 MW, whereas plant sizes range from 38 to 2558 MW. Boiler ages for these plants range from zero (new plants) to 60 yr old. The total annual quantity of emissions from these plants is equivalent to 5,734,629 tons of S per year, compared to an allowable emission rate of 3,236,764 tons/yr. Based on these projections, an average overall SO_2 removal efficiency of 44% would be required to bring these plants into compliance.

The method for using the output of the compliance tests to project costs for meeting the regulation by FGD is discussed below.

DEVELOPMENT OF THE SCRUBBING COST GENERATOR

The purpose of the scrubber cost generator is to provide a simplified, consistent method for projecting comparative costs for installing FGD systems on the power plants projected to be out of compliance with the regulation. Because of the limited amount of information available for input to the model, the projections are to be treated as general rather than specific in evaluation of the results.

The FPC data projections to 1978 and the output of the compliance test models are inputs to the model. The basis for its development and other relevant information concerning its use are discussed below.

Background

TVA in conjunction with EPA published a report entitled Detailed Cost Estimates for Advanced Effluent Desulfurization Processes (EPA 600/2-75-006; NTIS PB 242 541, January 1975) (7) which projects the economics of SO_2 control by two throwaway processes (limestone and lime slurry scrubbing) and three recovery processes (magnesia slurry-regeneration, Wellman Lord/Allied, and catalytic oxidation). As mentioned, the limestone, magnesia, and Wellman Lord/Allied are the primary FGD alternatives considered in the current study. The detailed "base" investment and operating cost projections given in the above report for these processes, and the method illustrated for scaling costs, were coded into a computer model to allow for projection of economics for these processes at other capacities based on using the 1978 FPC data projections discussed above.

The "base" data incorporated into the program correspond to scrubbing processes designed for 500-MW boilers, both new and existing, which burn 3.5% S coal (dry basis). They are assumed to emit 92% of the S in the coal overhead

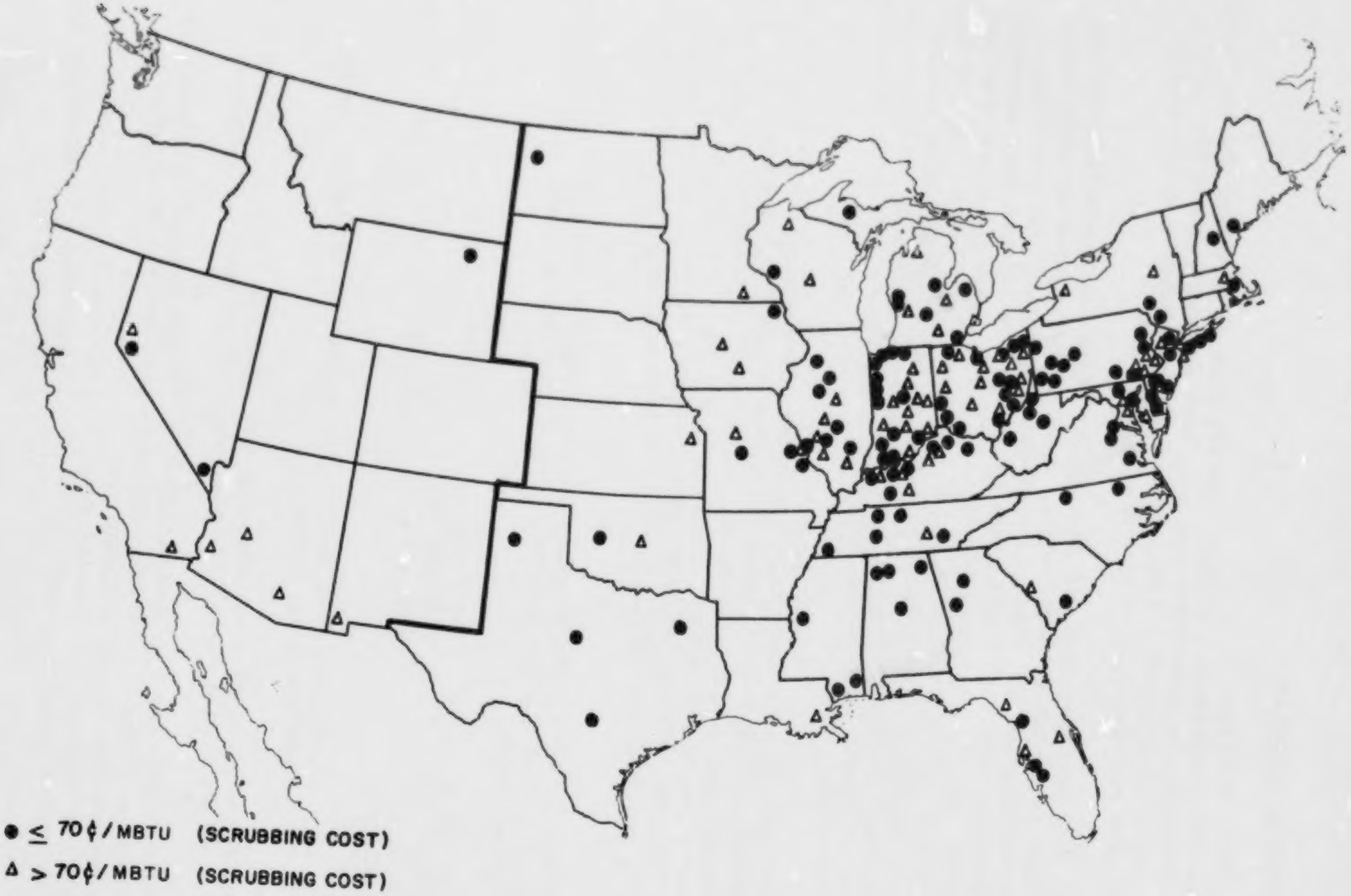

● ≤ 70¢/MBTU (SCRUBBING COST)
Δ > 70¢/MBTU (SCRUBBING COST)

Figure 17. Geographic distribution of 187 power plants projected out of compliance (1978).

as SO_2, and are designed to remove 90% of the SO_2. The processes were modified from the initial study to exclude the costs for particulate removal.

Investment Scaling Procedure

Direct Investment Scaling--

A method was established for using the FPC Form 67 data and the compliance test data to project the investment and unit revenue requirements for each power plant out of compliance. Quantities of air and S rates to the boiler for the base case are included in the data base.

Similar data are projected for each boiler which is determined from the compliance test to be out of compliance. Relative capacities are calculated to allow for scaling costs. Flue gas processing equipment and costs are estimated assuming that each boiler must be designed with separate, independent equipment. Absorbent preparation and effluent processing areas, however, are designed with common facilities at the plant level to process the combined quantities of absorbent and effluent from all of the boilers. This "common facility" concept minimizes the investment requirements because designing for installation of single large units rather than multiple small units results in an economy of scale.

The FPC Form 67 data base does not contain data specifying flue gas rates from the boiler to allow for scaling of the gas processing equipment (scrubbers, fans, reheaters, and duct). Therefore, costs for these areas are scaled on the basis of air rates to the boiler. Emission rates of S for each boiler are available from the compliance tests and are totaled for each boiler which requires SO_2 control; the total quantity is then used in scaling S processing costs.

The general form of the equations for scaling costs for (1) the flue gas processing areas and (2) the absorbent preparation and effluent processing areas are shown below:

$$\text{(1)}\quad \begin{array}{l}\text{Flue gas processing}\\ \text{area cost for}\\ \text{individual}\\ \text{boiler (I)}\end{array} = \begin{array}{l}\text{Base flue gas}\\ \text{processing}\\ \text{area cost}\end{array} \left[\frac{\text{Design air rate to boiler (I)}}{\text{Design air rate to base boiler}}\right]^{B1}$$

Where B1 = scaling exponent for the gas processing equipment whose costs are being scaled.

Total flue gas processing area costs for the plant are equal to the sum of the flue gas processing area costs for each boiler which requires scrubbers.

$$\text{(2)}\quad \begin{array}{l}\text{Absorbent prepara-}\\ \text{tion and effluent}\\ \text{processing area}\\ \text{common facilities}\\ \text{cost (entire plant)}\end{array} = \begin{array}{l}\text{Base absorbent}\\ \text{preparation and}\\ \text{effluent pro-}\\ \text{cessing area}\\ \text{cost}\end{array} \left[\frac{\begin{array}{l}\text{Total annual S throughput for}\\ \text{all boilers which require}\\ \text{scrubbers}\end{array}}{\begin{array}{l}\text{Total annual S throughput for}\\ \text{the base plant}\end{array}}\right]^{B2}$$

Where B2 = scaling exponent for the S processing equipment whose costs are being scaled.

Since the absorbent preparation and effluent processing areas are designed utilizing common facilities for the total throughput, these calculated costs do not need to be summed boiler by boiler.

The total direct investment is calculated as the sum of the total flue gas processing area and the common facilities costs.

Indirect Investment Costs--

Indirect investment costs are estimated as a percentage of the direct costs similar to the method used in the initial study. For simplification in developing the model, the indirect cost factors do not vary with plant or boiler size. Table 27 shows the indirect cost factors which are used in projecting total investment requirements for each of the three processes as a function of plant status (new or existing unit).

TABLE 27. INDIRECT INVESTMENT AND ALLOWANCE FACTORS (7)

	Indirect investment and allowance factors as a percent of direct capital investment			
	Limestone process		Magnesia and Wellman Lord/Allied processes	
	New	Existing	New	Existing
Indirect Investment Factors				
Engineering design and supervision	9	10	11	12
Construction field expense	11	13	11	13
Contractor fees	5	7	5	7
Contingency	10	11	10	11
Total indirects	35	41	37	43
Allowance Factors				
Startup and modifications	8	8	10	10
Interest during construction	8	8	8	8
Total allowances	16	16	18	18

Investment Adjustment Factors--

The data base was created to allow the input of other factors for adjusting process investment. A process premise factor is an allowable input to adjust the projected process investment for any of the four processes. The adjustment is applied uniformly for all plants. It allows the relativity of process investments to be varied from that reported in the initial study to reflect updated technology and costs and is applied separate from cost indices. For the current study, process premise factors for the limestone, sodium, and gypsum processes are input as 1.2, whereas the factor for the magnesia process is input as 1.3. These values adjust the relativity of the costs to conform with recent vendor cost data.

The data base also allows for the use of site-specific factors which can be used for any process and any plant to adjust the investment to take into account special design provisions which were not considered in the initial study. Factors were incorporated for some of the TVA plants to reflect the effect of a common plenum which would require fewer scrubbers, and to adjust for higher projected capacity factors in comparison with projected FPC factors.

Two additional factors which may be input to the program to impact process investment include (1) a retrofit difficulty factor (developed by PEDCo) and (2) a location factor. Each of these factors is applied specifically to all processes at a given location. The retrofit difficulty factor adjusts the projected investment equally for all processes at a given location to account for site-specific variations in design and layout which would affect costs for installation of each process alternative equally. Location factors are applied in the same manner to account for site-specific differences in construction costs which are related to plant location and terrain.

The FPC data file does not contain information specifying the number of flue gas ducts on existing boilers. Since the number of required scrubbing trains is a function of the number of ducts, power plants with gas flow rates of <700,000 sft^3/min were arbitrarily assumed to be designed with two ducts, whereas plants with larger flow rates were assumed to be designed with four ducts.

Revenue Requirement Scaling Procedure

Direct Costs--

Annual quantities of raw materials and utilities required for each processing area (i.e., absorbent preparation, scrubbing, reheat, SO_2 processing, etc.) are identified and are scaled from the "base" data proportional to the relative gas ratio or the relative S throughput ratio similar to the method for scaling investments. Labor and analyses requirements are scaled proportional to the relative gas or S throughput ratio raised to a fractional exponential power.

Utilities, such as humidification water, reheat, and electricity for the fan, are scaled proportional to the relative gas rate, whereas raw materials and utilities, such as absorbent and electricity for the S-processing areas, are scaled proportional to the relative S rate. Annual costs for raw materials and utilities are then calculated by applying the unit costs to the annual usage rates.

Projected unit costs for raw materials and utilities for 1978 are shown in Table 28 with the exception of limestone and sludge disposal. A program with the supporting data base was developed for calculating the delivered cost of limestone to each power plant considered in the study. Details are outlined in Appendix K.

Maintenance is estimated as a percent of the subtotal direct investment at the rates indicated in Table 29. Conversion operating costs are defined as the sum of utility, labor, maintenance, and analyses costs. Direct costs are defined as the sum of raw material plus conversion costs.

TABLE 29. ESTIMATED MAINTENANCE RATES FOR ALTERNATIVE FGD PROCESS (7)

Process	Maintenance rate, % of direct investment
Limestone	8
Magnesia	7
Wellman-Lord/Allied	6

Indirect Costs--

The capital charges included in the indirect operating costs are applied as average capital charges, including depreciation, interim replacements, insurance, and cost of capital and taxes. Depreciation is straight line over the remaining life of the plant (based on an assumed useful life of 30 yr). The capital charge allocation for interim replacements varies as a function of the remaining life of the plant. For a new plant it is allocated as 0.67% of the total investment, but declines to zero for plants with <20 yr of remaining life. Insurance is allocated as 0.50% of total investment for all plants. The overall breakdown of capital charges included in the cost projections is shown in Table 30 (7).

For each process, plant overhead is estimated as 20% of conversion costs, and administrative overhead as 10% of operating labor. Administrative overheads in the initial study (7) were calculated on a different basis for processes producing a salable byproduct as compared to sludge producing processes to take into account the costs for marketing the byproducts. For this study, however, the byproduct prices are assumed to be net prices after marketing expenses have been deducted; therefore, administrative overheads are calculated by the same procedure for all processes.

Subtotal indirect costs are defined as the total of capital charges, and plant and administrative overheads. Total annual revenue requirements are defined as the total of direct plus indirect costs.

TABLE 28. PROJECTED 1978 UNIT COSTS FOR RAW MATERIALS, LABOR, AND UTILITIES

	Unit cost, $
Raw Materials	
Limestone	Variable[a]
Lime	42.00/ton
Magnesium oxide	215.00/ton
Coke	28.00/ton
Vanadium pentoxide catalyst	2.20/l
Sodium carbonate	78.00/ton
Antioxidant (sodium process-scrubbing)	2.75/lb
Sulfuric acid	54.00/ton
Labor	
Operating labor	10.00/hr
Analyses	15.00/hr
Utilities	
Fuel oil, No. 6	0.35/gal
Natural gas	2.50/kft^3
Steam (500 psig)	1.40/klb
Process water	0.06/kgal
Electricity	0.027/kWh
Heat credit	1.15/MBtu
Water treatment	1.20/kgal
Sludge transportation fee (offsite disposal variation)	1.00/ton[a]

[a] See details in Appendix K.

TABLE 30. ANNUAL CAPITAL CHARGES FOR POWER INDUSTRY FINANCING (7)

	As percentage of original investment		
	Years remaining life		
	30	25	20
Depreciation, straight line (based on years remaining life of power unit)	3.33	4.00	5.00
Interim replacements (equipment having less than 30-yr life)	0.67	0.40	-
Insurance	0.50	0.50	0.50
Total rate applied to original investment	4.50	4.90	5.50
	As percentage of outstanding depreciation base[a]		
Cost of capital (capital structure assumed to be 50% debt and 50% equity)			
Bonds at 8% interest	4.00		
Equity at 12% return to stockholder	6.00		
Taxes			
Federal (50% of gross return or same as return on equity)	6.00		
State (national average for states in relation to Federal rates)	4.80		
Total rate applied to depreciation base	20.80[b]		

a. Original investment yet to be recovered or "written off."

b. Applied on an average basis, the total annual percentage of original fixed investment for a plant with 30 yr remaining life would be 4.5% + 1/2(20.80%) = 14.90%.

Output of the Scrubbing Cost Generator

The overall output of the scrubbing cost generator includes the following information for each of the three scrubbing alternatives considered:

1. Plant investment

   $
   $/kW

2. First-year costs excluding byproduct revenue

   $
   Mills/kWh
   Cents/MBtu

3. Byproduct

   Production rate, tons/yr
   Equivalent cost, $/ton

4. Incremental process cost in comparison to limestone scrubbing

   $
   $/ton of byproduct

An example output is shown in Table 31.

The data generated in the scrubbing cost model are used to calculate the scrubbing costs of a throwaway system versus a salable byproduct for each of the 833 boilers identified in this study as operating out of compliance with pollution control laws in 1978.

The scrubbing costs for fossil fuel power generation are expressed in cents/MBtu for convenience in comparing them with clean fuel alternatives. Use of low-S fuel is also a realistic alternative to FGD which must be considered for meeting compliance regulations. The alternative clean fuel level (ACFL) represents the amount of premium that one can pay for fuel that is low enough in S to meet compliance in lieu of scrubbing with an FGD system.

The model also calculates the cost differential between scrubbing with a limestone throwaway system versus MgO-acid producing system. This comparison is based on the quivalent of 100% H_2SO_4 for both systems. This accommodates identifying the incremental cost difference of the two systems for all boilers or combinations of boilers included in the model.

The lowest cost scrubbing system is limestone scrubbing at all plants in the model except for a unique type of plant, that is, a large (500-MW) new plant burning a low-S fuel such as oil and yet is exceeding SIP regulations. MgO-acid scrubbing in this instance is lower in cost as compared to limestone scrubbing. Such plants were handled in the model with a zero incremental cost in lieu of using the negative cost.

TABLE 31. SAMPLE OUTPUT OF SCRUBBING COST GENERATOR

	Compliance costs from 1978 projections		
Plant code: 000000-0000			
PLANT NAME: X			
Capacity factor, %			
Coal	56.5		
Oil	2.5		
Gas	0.1		
S content, %			
Coal	3.2		
Oil	1.5		
Total capacity, MW (12 boilers)	1,275		
Total scrubbed, MW (5 boilers)	1,109		
Process	Limestone	Magnesia	Wellman-Lord/ Allied
Investments			
$	80,152,545	95,996,739	104,861,270
$/kW	72.3	86.6	94.6
First year costs (byproduct revenues excluded)			
$	45,078,254	52,957,830	67,973,845
Mills/kWh	6.82	8.02	10.29
Cents/MBtu	65.7	77.2	99.1
Byproduct	Sludge	H_2SO_4	S
Tons/yr	426,094	228,181	68,399
Cost, $/ton	105.8	232.1	993.8
Incremental costs in comparison to limestone process			
$	0	7,879,576	22,895,591
$/ton	0	35	335

Costs for production of S by the Wellman-Lord/Allied process were higher in all cases studied than production of H_2SO_4. Projected savings in distribution costs for S compared to H_2SO_4 did not offset the incremental production costs. Costs for use of the Wellman-Lord/Allied technology will be more clearly defined during the current full-scale demonstration, partially funded by EPA, at the Mitchell Station of the Northern Indiana Public Service Company. Revised information will be included in the model. Also, EPA is currently sponsoring work with ESEERCO (Empire State Electric Energy Research Corporation) and Niagara Mohawk to develop the Atomics International process for producing S from SO_2 in stack gas. This technology and other work involving use of solid reductants could lead to lower costs for production of S as an alternative to producing H_2SO_4.

Several factors that are difficult to incorporate into a generalized economic model could have a significant influence on the choice of byproducts. The incentive for production of S is high because it is a safe, noncorrosive, convenient material to handle, and can be easily stockpiled for long periods of time at relatively low cost. Because of the latter advantage, S could be incorporated more easily into the existing market. Moreover, fluctuations in market demand could be met with less impact to both the producer and consumer. S also has the advantage of being more economical to ship than acid, especially for long distances.

In the computer program used for the marketing study, the model assumes that acid plants that could be supplied with byproduct acid at a lower cost than their own production costs (including cost of raw material S) would shut down and purchase byproduct acid to sell to their customers. This would involve a strong commitment to use of the byproduct because personnel to man the acid plant could not be kept on standby nor would a guaranteed supply of S be available on short notice. The acid distributor would very likely prefer to purchase byproduct S (at a lower price than natural S) to supplement or replace his traditional supply. Also, H_2SO_4 plants normally generate steam from burning S for use in other plant operations. It would be necessary to replace this available energy with an alternate supply requiring the burning of additional coal or fuel oil. Facilities for replacement steam production could cost more than the savings from purchase of byproduct acid. S would be favored over acid as a byproduct in those power plant locations where an existing S terminal is already in operation. There are a number of such terminals on the East Coast. The facilities required for handling molten S would be of little value in handling acid. Also, S would be the preferred byproduct in extremely cold climates. The freezing point of acid varies with concentration, but 98% acid will freeze at about $40^{\circ}F$. Long-term storage of acid would be much more expensive and difficult under these conditions. Another situation when S would be favored is for power plants in the Western States where the limited acid market is controlled by smelters. Shipping S to the eastern market would be more economical than acid.

It is likely that a mix of marketable byproducts will ultimately provide the least-cost compliance with SO_2 regulations in the utility industry. Technology for production of S should be fully developed so that the choice is available and so that accurate information is available for cost comparisons with other methods of control.

The cost information from the scrubbing cost model becomes input to the marketing model which is designed to determine the potential for the production and marketing of byproduct H_2SO_4 at the various power plant locations. The data can also be used to generate a supply curve for the production of abatement H_2SO_4.

Supply Curve for Abatement Acid

A demand curve for abatement acid was presented in Figure 6. For illustrative purposes it is useful to consider the supply curve that would be traced out by different levels of a uniform f.o.b. steam plant supply cost for H_2SO_4. This ignores steam plant location relative to acid plants. Such a curve can be estimated by ranking power plant boilers from lowest to highest cost for producing H_2SO_4 and accumulating supply quantities shown in Figure 18. The range of supply costs is much greater than those for demand. While about 9 Mtons of acid is available at an infinite price, supplies greater than about 8 Mtons is unreasonable.

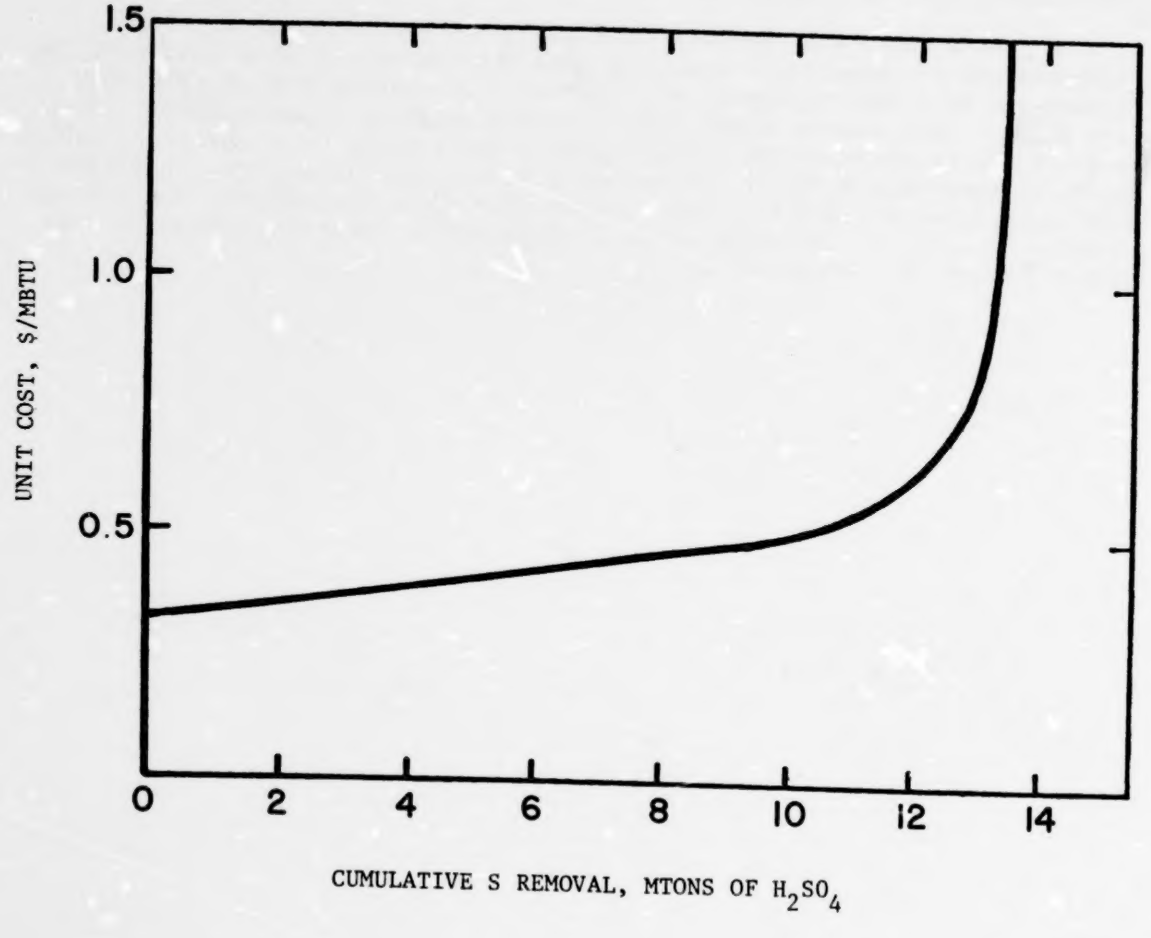


Figure 18. The supply cost•curve for abatement acid.

ABATEMENT BYPRODUCT ACID DISTRIBUTION-TRANSPORTATION SYSTEM

To assess representative competitive costs, this market system analysis must generate accurate S freight rates from the Frasch S sources to the acid plants and H_2SO_4 freight rates from all power plants to all H_2SO_4 plants. This represents more than 300,000 possible rates which is a prohibitive manual task. Also, the overall market study series calls for a possible expansion to evaluate $CaSO_4$ for wallboard, ammonium sulfate $[(NH_4)_2SO_4]$, and several other fertilizer classifications; therefore, the task becomes increasingly demanding.

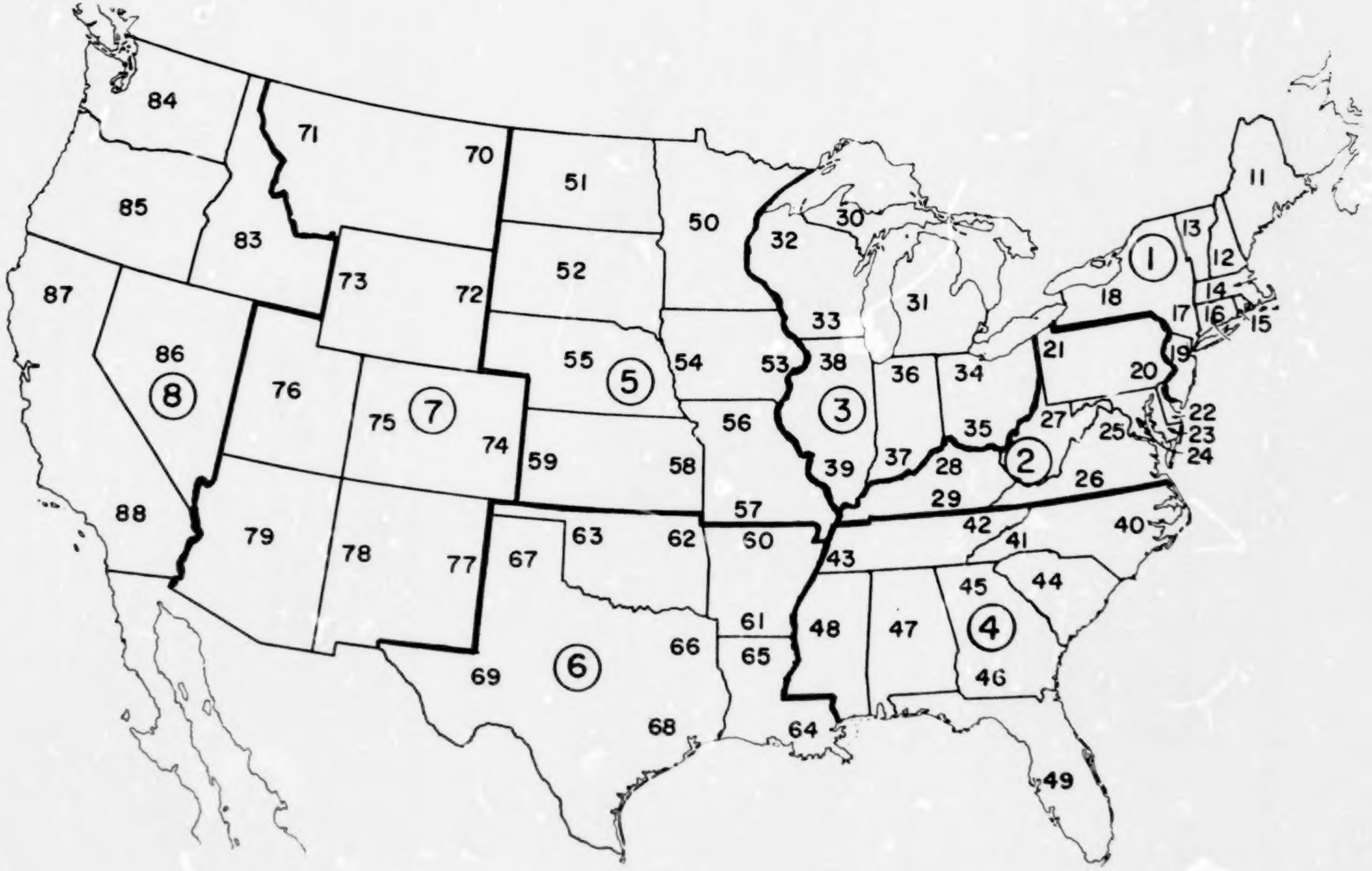
STANDARD POINT LOCATION CODE

The logistical linkage between the H_2SO_4 and power plant data bases and the rate generation system is the Standard Point Location Code (SPLC). This is a transportation-oriented, six-digit number prescribed by the National Motor Freight Traffic Association under the guidance of the SPLC Policy Committee. The system is similar to U.S. mail zip codes. Figure 19 shows location areas to the first two-digit level. The first digit indicates a region relating to major traditional traffic associations. The first two digits uniquely identify a state or a portion thereof. As more digits are added, smaller nested areal units are identified. The third digit gives a cluster of counties, the fourth digit a county, the fifth digit a cluster of points within a county, and the sixth digit identifies all rail and truck specific points.

DISTRIBUTION COST GENERATION

A logic flow diagram of the freight rate generation system used in this model is shown in Figure 20. It shows that an SPLC for a power plant origin and one for an H_2SO_4 plant destination are input to the National Rate Basis Tariff 1-C (NRBT 1-C). This tariff determines for rail rate purposes the basing points for the origin and destination. While there are about 60,000 rail points, there are only 2,632 basing points east of the Rocky Mountains.

Outputs from the NRBT 1-C block in Figure 20 are two sets of codes used to define mileage and tariff rates between the byproduct shipping origin and destination points. One set--Index 1 and Index 2--is used to determine the appropriate rate base mileage to be applied. The two index values are pointers to a 3.5 M record triangular mileage file compiled from 12 tariffs resulting from the landmark 1945 Interstate Commerce Commission hearing entitled "Docket 28300." (Short line rail mileage published in the twelve "28300 Class Tariffs" by all railroads operating east of the transcontinental



84
71
70
51
11
50
30
85
32
13
1
83
12
52
18
14
87
73
72
33
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49

Figure 19. Geographic identification of Standard Point Location Codes (SPLC).

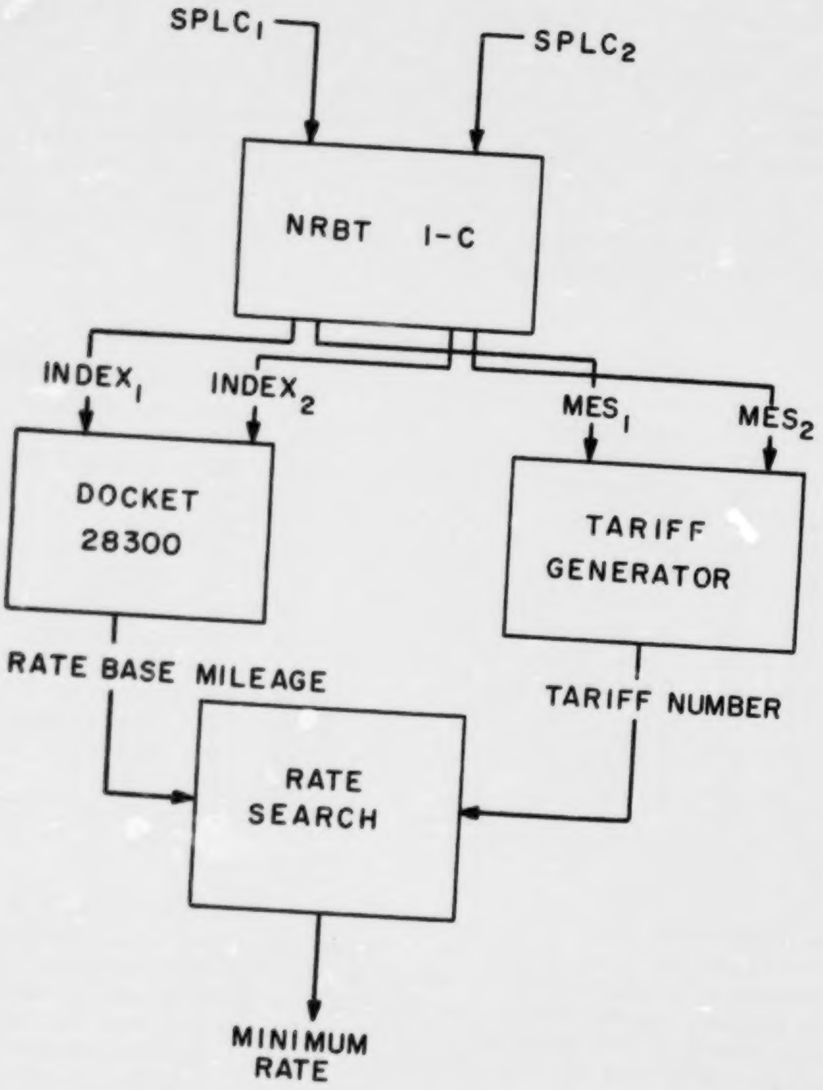
SPLC1
SPLC2
NRBT I-C
INDEX1
INDEX2
MES1
MES2
DOCKET 28300
TARIFF GENERATOR
RATE BASE MILEAGE
TARIFF NUMBER
RATE SEARCH
MINIMUM RATE

Figure 20. Flow diagram of freight rate generation model.

territory outlined in Figure 21). The file includes rail (and some truck) tariff mileage for shipments within and between five major freight associations shown in Figure 21. Output from the Docket 28300 block of Figure 20 is a rate base number that can be thought of as a type of mileage.

The second group of codes output from the NRBT 1-C define the mutually exclusive set (MES) numbers for the origin and destination points and serve as input to the Tariff Rate Generator block to choose the appropriate tariff. Figure 21 shows the location of the nine rate territories (MES Nos.) east of the Rockies. Identification of the nine territories is necessary due to overlapping application of the five major freight rate territories. The remaining 10 MES numbers as shown in Table 32 are those base points which by virtue of unique circumstances or borderline applications necessitates separate listing. The result is a total of 19 MES numbers for basing points in the Docket 28300 tariffs. Given the MES for both the origin and destination it can be determined in which tariff(s) these points can be found, which is output from the Tariff Generator block in Figure 20.

TABLE 32. RECLASSIFICATION OF BASE POINTS

10	KY	Lexington
10	KY	Winchester
11	KY	Chilesburg
12	DC	Washington
12	VA	Norfolk
12	WV	Charleston
13	VA	Alberta (S)
13	VA	Altavista (S)
13	VA	Burkeville (S)
13	VA	Lynchburg (S)
13	VA	Petersburg (S)
13	VA	Suffolk (S)
14	VA	Bristol
14	VA	Norton
14	VA	St. Paul
14	TN	Bristol
15	SC	Anderson Quarry
15	SC	Rion
16	NC	Bunn
16	TN	Brownsville
17	IL	Sparta
18	NY	Pulaski
19	IN	Cannelton
19	IN	Corydon
19	IN	Ferdinand
19	IN	Huntingburg
19	IN	Marengo
19	WV	Olcott

The importance of knowing not only the mileage but also the tarrif number is illustrated in Figure 22. Shown are H_2SO_4 rail rates within four major freight associations as a function of rate base numbers. A slight error in mileage is not nearly as critical as knowing which tariff applies. Also these are the only published H_2SO_4 rates. Rates for the other eight tariffs were generated by the TVA Navigation and Regional Economics Branch (Division of Navigation Development and Regional Studies) from those using sound traffic legal arguments similar to the negotiation process that would ensue should large acid movements become a reality. In Figure 20 rate base and tariff numbers are input to the Rate Search block and the minimum rate is output for use in the transportation cost model.

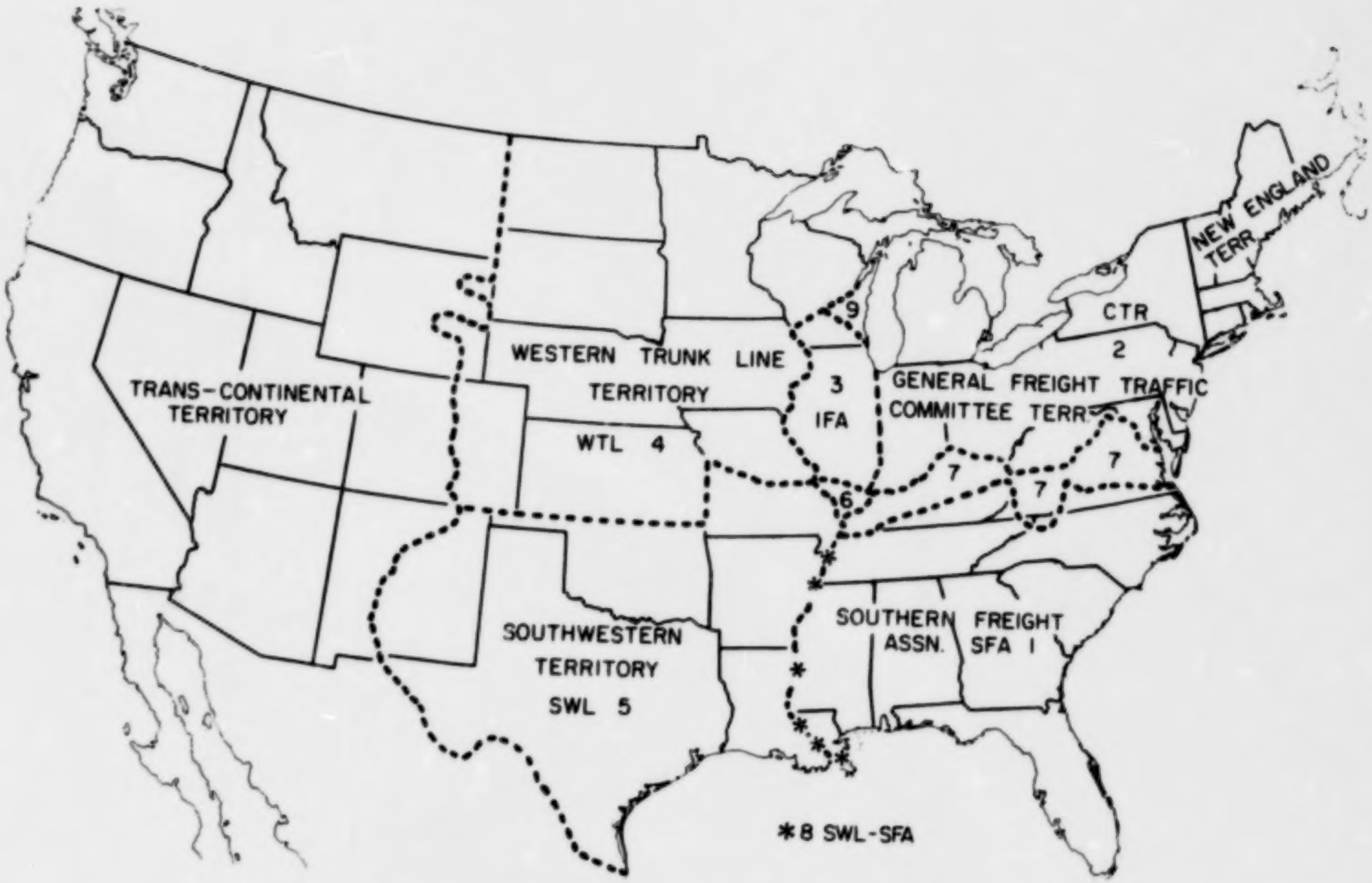
NEW ENGLAND TERR.
CTR
2
GENERAL FREIGHT TRAFFIC COMMITTEE TERR.
1
7
7
7
9
3
IFA
6
WESTERN TRUNK LINE TERRITORY
WTL 4
TRANS-CONTINENTAL TERRITORY
SOUTHWESTERN TERRITORY
SWL 5
SOUTHERN FREIGHT ASSN.
SFA 1
*8 SWL-SFA

Figure 21. Railroad rate territories.

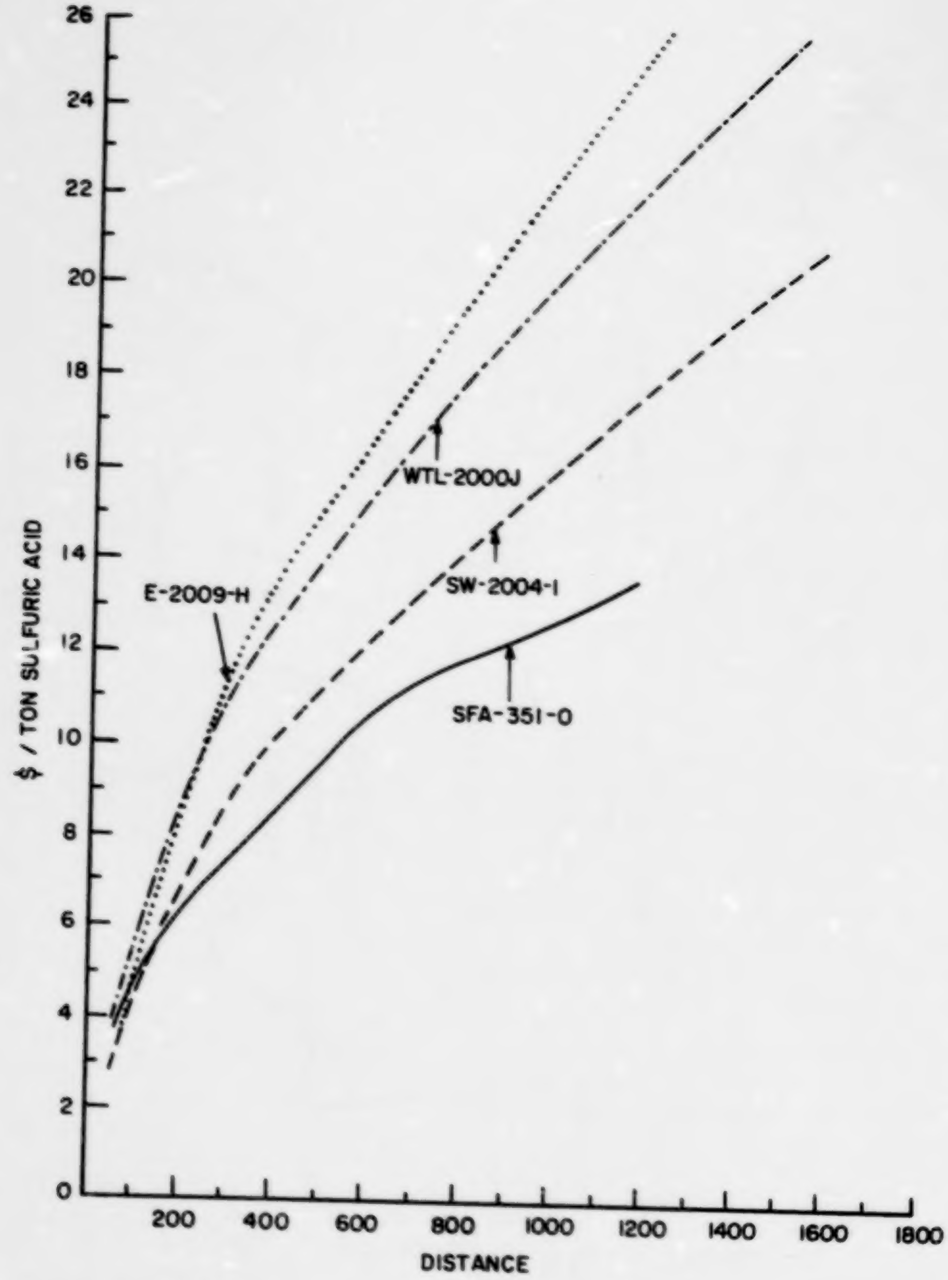

Figure 22. Four basic commodity column tariffs for H_2SO_4 rail shipments.

MARKET SIMULATION MODEL THEORY

Objective of the overall marketing model is to simulate long-run competitive equilibrium S and H_2SO_4 market conditions in the U.S. as might be impacted by recovery of byproducts from SO_2 control in the power industry. To simulate these conditions, total cost of both the H_2SO_4 and power industries is minimized subject to the condition that acid production (demand) is still met, either from traditional S sources or from substitution of abatement H_2SO_4.

The model is similar to the classic transportation model of linear programing where demands represent H_2SO_4 plant customers and supplies represent either production at each of the commercial acid plants or purchases from any power plant boiler capable of producing acid. Incurred (transfer) costs represent either H_2SO_4 production cost using Port Sulphur S in the first case or boiler scrubbing cost plus transportation cost to the respective acid plants in the second case. A mathematical statement of the model is outlined in Appendix B.

ECONOMIC THEORY

Through the use of several simplifying assumptions, the complex process taking place in the model can be conceptualized in terms of classical supply and demand curves.

If spatial considerations could be ignored, the demand (price) curve in Figure 6 and the supply (cost) curve in Figure 18 could be plotted on the same graph as in Figure 23; where they intersect would represent supply-demand equilibrium.

It was explained earlier, and summarized in Figure 6, that from the H_2SO_4 plant data base and the long-run average acid production cost generator, all commercial acid producers can be ranked in terms of a demand curve. A conceptual f.o.b. power plant acid demand curve DD' is shown in Figure 23. At high abatement supply price levels, only the smallest, oldest, most remotely located acid plants would be interested in curtailing production and buying abatement acid. As supply price declines, more acid producers buy until even the largest, newest plants located near S supply sources become candidates.

Likewise, as explained earlier and summarized in Figure 18 boilers can be ranked in terms of a supply (cost) curve, f.o.b. each power plant such as SS' in Figure 23. The intersection of such a supply curve with the conceptual

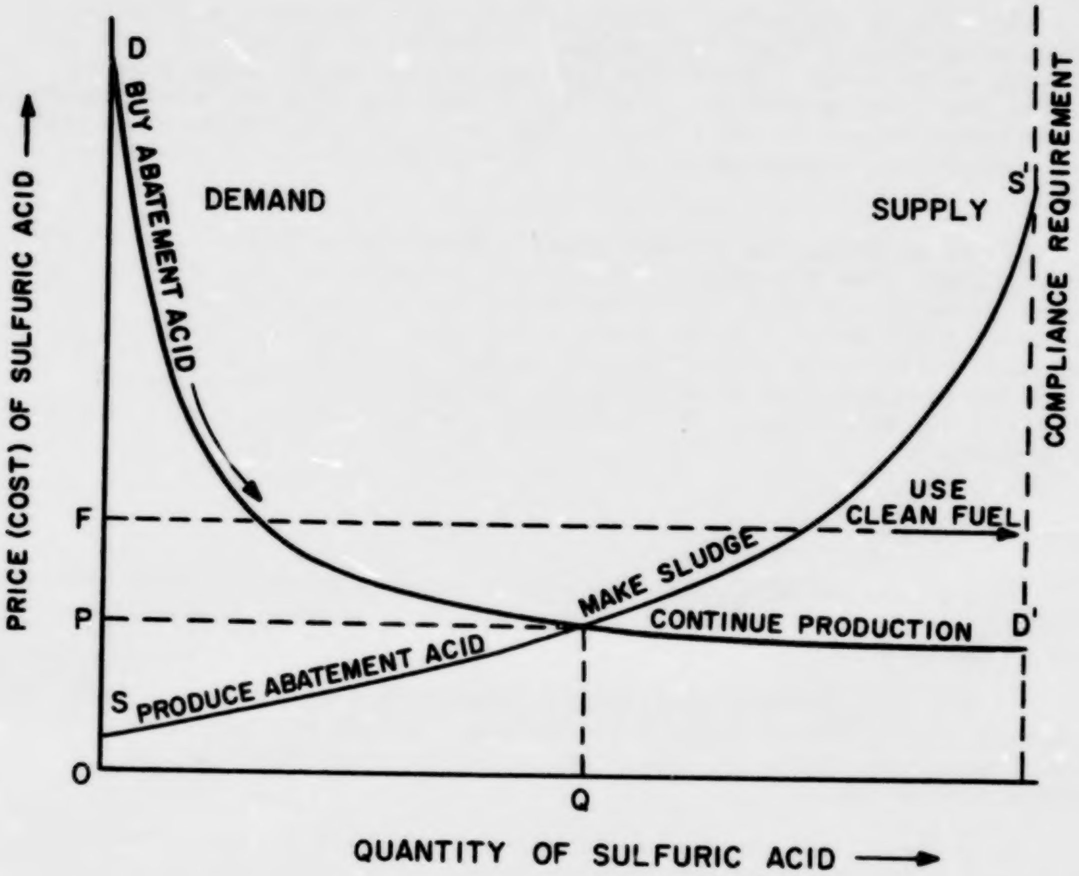

Figure 23. Conceptual demand curve for H_2SO_4 and supply curve for abatement production.

demand in Figure 23 would represent an equilibrium position at point Q. The price F represents the alternative of buying complying fuel.

From the demand curve DD', H_2SO_4 producers above equilibrium price P would find it profitable to buy acid from steam plants rather than continuing production. Those less than price P would find it more profitable to continue production.

From the supply curve SS', boilers below price P would find it feasible to use a scrubbing strategy that produces H_2SO_4, while those above price P but less than price F would profit from using a scrubbing strategy that produces and disposes calcium (Ca) sludge. Those above price F would find it more profitable to use a clean fuels strategy in lieu of scrubbing, assuming that such clean fuel is available.

Multidimensional Equilibrium Model

While the preceding simplified economic description presents the essence of the economic model, a more elaborate spatial equilibrium model is required for realistic analysis. The problem is that the lowest acid cost boiler could be close to or far from the highest cost commercial acid plant. It therefore is necessary to trace a demand curve for a single source (location) of supply. This could be done for every supply point, but would be of no analytical significance unless there was only one supply point being considered. As soon as more than one supply point is considered, competition develops for demand points. Hence, while traditional supply-demand concepts are helpful in exploring the basic underlying economic structure of flue gas marketing alternatives, a much more elaborate multidimensional equilibrium model is required before analytical conclusion can be drawn.

The model implicitly ranks potential acid buyers as described earlier under the demand for abatement acid except that every potential abatement acid producer is given his own view of the market with reference to his specific location. As the model is being solved this view is dynamically changed to reflect the bidding away of markets by other potential abatement producers. The decision-making process might be viewed in two stages (1) the utility manager is bidding for markets at a given price and (2) based on results of the bidding decides if production of acid is the least-cost alternative. The results of this bidding process, of course, interacts with his abatement strategy decision. The task of simulating this process from the viewpoint of 104 acid producers and 833 steam plant boilers can be solved with modern computers and linear programing techniques. The solution reveals not only which acid producers would buy and which power plants would sell H_2SO_4, but also which power plants would sell to which acid plants. The mix of abatement strategies and marketing patterns resulting in the lowest possible cost to the combined industries (society) is said to be optimal. Such a solution simulates the result of long-run competitive equilibrium solutions. Any variation to this optimal solution would increase the total cost to both industries.

The model is designed to place alternative strategies for controlling emissions in perspective for each power plant in relation to the alternatives available to all other power plants. The model addresses only those plants that are projected to be out of compliance in 1978. The strategies considered include (1) the use of clean fuel, (2) scrubbing with limestone to produce a throwaway sludge, and (3) scrubbing with MgO to produce H_2SO_4 as a marketable product. It is obvious that the lower the cost of clean fuel the less justification utilities would have to use FGD. However, clean fuel is more expensive than traditional fuel supplies. The premium cost for complying fuel is assumed to be the limit on the net cost of scrubbing. That is, as the premium for clean fuel increases the more the utility industry can pay for FGD systems.

If scrubbing is the least-cost option the model chooses between the use of limestone scrubbing technology or the production of abatement acid; costs for production of S by the Wellman-Lord/Allied process were higher in all cases studied than production of H_2SO_4. If the incremental cost of scrubbing with MgO to produce H_2SO_4 compared with limestone scrubbing can be recovered by marketing H_2SO_4 in the existing market then the power plant would choose the acid-producing strategy.

The model considers total cost of both the H_2SO_4 and power industries and chooses the set of alternatives that minimize the total cost. H_2SO_4 producers are given a choice of continuing production or buying acid from any steam plant.

RESULTS AND ANALYSIS

PLANTS OUT OF COMPLIANCE IN 1978

The operating characteristics of all 800 U.S. power plants projected to be in operation in 1978 are outlined in Table 33. Also included in this table are the characteristics of the plants projected to operate out of compliance in 1978.

As the data in the table indicate, 187 power plants out of a total of 800 were calculated to be out of compliance. It should be noted that many of the plants estimated to be out of compliance are likely on compliance scheduled that are different from those selected for this study. Even though plants out of compliance make up only 32% of the total population with respect to capacity, they burn about 50% of the total coal; only 20% of the total oil and only 5% of the total gas. Plants out of compliance have a 30% higher S content in the coal burned and a 43% higher S content in the oil burned than the overall nationwide average. The average boiler size for plants out of compliance was about 30% greater than the average for all plants. The age range of boilers, the range of boiler sizes, and boiler capacity factor for plants out of compliance were not significantly different from the industrywide values.

ACFL

The ACFL is defined as the premium price for fuel that will meet the applicable SO_2 emission regulation. Determination of the actual premium paid for complying fuel in the utility industry is beyond the scope of this study. Also, the availability of complying fuel was not considered. The ACFL selected for the model runs ($0.35, $0.50, and $0.70/MBtu) were chosen to show the effect on potential volume of abatement acid. However, the range covered should be representative of most actual situations. Extreme values were used to demonstrate that at low premium price, scrubbing is not competitive while at high premium values, FGD is the economic choice. The results of these calculations for all plants estimated to be out of compliance in 1978 are shown in the following tabulation:

Reduction in Emissions

Clean fuel premium, cents/MBtu	ktons S		Annual cost, $	
	Clean fuel	Scrubbing	Clean fuel	Scrubbing
25	4,440	-	1,172,406,000	-
150	98	4,342	159,200,000	2,323,553,000
∞	-	4,440	-	2,866,244,000

TABLE 33. POWER PLANT OPERATING CHARACTERISTICS PROJECTED FOR 1978

	1978 all U.S. plants	1978 plants out of compliance
No. of power plants	800	187
No. of boilers	3,382	833
Total capacity, MW	411,000	132,600
Total fuel		
Coal, ktons	475,600	226,800
Coal, GBtu	10,408,300	5,125,100
Oil, kbbl	620,300	110,200
Oil, GBtu	3,827,400	686,900
Gas, Mft^3	2,556,000	108,200
Gas, GBtu	2,602,200	167,000
Average S content of coal, %	2.12	2.81
Average S content of oil, %	0.99	1.42
Emissions, equivalent tons H_2SO_4		
Total emitted	29,552,100	17,562,300
Required abatement	9,912,600	9,912,600
Average capacity factor, %	31.87	35.12
Average boiler generating capacity, MW	122	159
Age of boilers, %		
0-5	5	10
6-10	8	10
11-15	8	6
16-30	42	42
>30	37	32
Size of boilers, %		
<200	82	75
200-500	11.7	15
501-1000	6	9
>1000	0.3	1
Capacity factor of boilers, %		
<20	40	35
20-40	20	17
41-60	23	29
>60	17	19

Based on the inputs used to calculate scrubbing costs in this study, the above tabulation indicates that at \$0.25/MBtu ACFL no scrubbers would be used. Clean fuel would be the logical strategy for controlling emissions. If clean fuel cost is >\$1.50/MBtu heat input, very little clean fuel would be used and scrubbing would be the strategy for controlling the major portion of SO_2 emissions. The scrubbing costs are based on the least-cost method without credit for byproduct sales which is normally limestone scrubbing.

The total costs shown illustrate that if clean fuel were available at \$0.25/MBtu premium, annual cost of compliance would be \$1.17G (G = 1 billion) while at a premium of \$1.50 compliance would be mainly by scrubbing at a cost of nearly \$2.5G.

RESULTS AND ANALYSIS OF BYPRODUCT SMELTER ACID MARKET

The first model run was made at a zero ACFL so that all power plants chose a clean fuel strategy leaving only the smelters participating in the market. As was expected, the smelter acid was fully integrated into the acid market projected for 1978. When the clean fuel premium for the utility industry was set at the \$0.35/MBtu ACFL level, eight power plants produced and sold acid in competition with the smelters. The distribution changed slightly, but the total smelter capacity, 1,756,000 tons, was moved into the market. When the ACFL was increased further to \$0.50/MBtu and \$0.70/MBtu, competition from power plant acid reduced the amount of byproduct acid that can be sold by the western smelters. The results of all the runs on smelter acid distribution are summarized in Table 34. At the \$0.50/MBtu level, power plant acid replaced 20% of the western smelter acid and at the \$0.70/MBtu level, over 70% of the market for western smelter acid was lost to acid produced by power plants. Because of their close proximity to the industrial areas of the U.S., all of the eastern and Canadian smelter acid was sold in competition with the power plant acid at all levels of clean fuel premium. The analysis of model runs indicates that the location of the western smelters with respect to the H_2SO_4 market places them at a disadvantage in competition with power plants located in vicinity of the industrial sector of the Eastern U.S. If the power plants develop such markets, the western smelter would have to equalize the price in order to compete. The only other option available to the western smelter would be to neutralize any excess byproduct acid that cannot be used for leaching of low-grade feedstock.

The supply points identified with the sale of byproduct smelter acid in each of the model runs are outlined in Appendix L.

RESULTS AND ANALYSIS OF POWER PLANT ABATEMENT ACID MARKET

Scrubbing Cost Generator Prescreen

The scrubbing cost generator was used to identify scrubbing candidates for all 187 power plants operating out of compliance at each of the three selected values of ACFL. The results are tabulated as follows:

TABLE 34. BYPRODUCT SMELTER ACID DISTRIBUTION IN MODEL RUNS

(ktons)

		ACFL, cents/MBtu			
		0	35	50	70
Eastern smelters					
Direct sales		818	818	818	818
Total Eastern		818	818	818	818
Canadian smelters					
Via Buffalo terminal		165	165	200	200
Via District terminal		35	35	-	-
Total Canadian		200	200	200	200
Western smelters					
State	Terminal				
Arizona	Houston	118	118	118	118
New Mexico	Chicago	304	304	155	81
	Baton Rouge	76	76	50	-
	St. Louis	-	-	166	-
	Houston	-	-	9	-
Utah	Memphis	96	96	-	-
	St. Louis	-	-	96	-
Montana	St. Louis	46	46	-	-
	Memphis	98	98	-	-
Total Western		738	738	594	199
Total byproduct smelter acid		1,756	1,756	1,612	1,217

	ACFL, cents/MBtu 35	 50	 70
Plants with scrubbing costs lower than ACFL	19	74	116
Plants with scrubbing costs higher than ACFL	168	113	71

All power plants with an FGD acid-producing potential of <66,000 tons/yr were excluded from the acid-producing candidates because acid plants with a lower production capacity would be too small to be competitive. Such plants were given the choice of choosing a limestone or a clean fuel strategy in the model.

For some power plants with multiple boiler installations, a mix of alternative methods produced the least-cost compliance strategy. The results of the prescreen are outlined in the following tabulation:

Total U.S. (187 plants)

Prescreen	ACFL, cents/MBtu 35	 50	 70
1. All clean fuel	168	113	71
2. All limestone scrubbers	6	25	48
3. Mixed limestone scrubbers and clean fuel	4	3	8
4. Potential MgO-acid scrubbers	9	40	58
5. Potential MgO-acid scrubbers and clean fuel	0	6	2
	187	187	187

Compliance Strategies Selected by Power Plants in Model Runs

The market simulation model was run to determine which of the potential acid-producing power plants would be viable candidates for marketing abatement acid in competition with byproduct acid from smelters. A summary of the distribution of strategies at the ACFL is shown in the following tabulation:

Compliance strategy	ACFL, cents/MBtu 35	 50	 70
1. All clean fuel	168	113	71
2. All limestone scrubbers	7	41	77
3. Mixed limestone scrubbers and clean fuel	4	7	10
4. MgO-acid scrubbers	8	24	29
5. Mixed MgO-acid scrubbers and clean fuel	0	2	0
	187	187	187

Many of the potential acid-producing plants identified in the scrubber cost generator prescreen run used limestone scrubbing in the long-term equilibrium model solution. The switch from recovery to a throwaway method resulted from the increased transportation costs at the higher abatement acid production levels. The potential production and marketing of abatement acid for the power plants that selected MgO-acid scrubbing strategy in each of the model runs is outlined as follows:

	ACFL, cents/MBtu		
	35	50	70
Potential production and marketing acid, ktons	2,554	5,108	5,595

A listing of the specific power plants that chose the acid scrubbing strategy in each of the three alternative clean fuel model runs is outlined in Tables 35-38. The tables include plant number, location, megawatts, Btu scrubbed, and tons of acid produced.

TABLE 35. EIGHT POWER PLANTS SCRUBBING, PRODUCING, AND MARKETING ACID IN $0.35 ACFL RUN

Plant No.	Location	MW	Btu scrubbed	Tons of acid
1395000250	North Carolina	2,286	99,526,110	105,209
3800000800	Pennsylvania	1,600	100,763,230	241,426
4510000100	Alabama	910	54,170,170	68,824
4740000300	Florida	1,136	71,443,680	250,963
4770003000	Kentucky	2,558	121,162,120	628,358
4770004100	Tennessee	2,550	12,853,680	572,320
4815000400	Ohio	1,831	132,159,990	254,335
4820001800	Michigan	2,462	141,227,650	433,206
Total		15,443	733,357,630	2,554,641
Average		1,930	91,669,703	319,330

A geographic distribution of the 187 power plants included in the model runs is outlined in Figure 17. This figure also identifies the plants that chose a clean fuel strategy in the $0.70/MBtu ACFL model run as well as the plants that chose a scrubbing strategy. In the latter group of 116 plants, 29 produced and marketed acid, and 81 used a clean fuel strategy. A tabulation of estimated scrubbing and clean fuel use in compliance strategies is presented in Appendix M.

TABLE 36. TWENTY-FOUR POWER PLANTS SCRUBBING, PRODUCING, AND MARKETING ACID IN $0.50 ACFL RUN

Plant No.	Location	MW	Btu scrubbed	Tons of acid
0700000550	New York	1,200	50,142,240	75,016
0785000500	Illinois	590	23,955,530	77,549
0790000100	Illinois	602	29,939,960	96,692
1115001300	Illinois	1,271	66,538,760	281,208
1395000250	North Carolina	2,286	99,576,110	105,209
1655000300	Florida	964	50,383,440	192,742
1790002550	Georgia	1,792	72,759,860	253,367
1790002800	Georgia	1,820	88,005,410	255,939
2455000250	Kentucky	1,011	56,196,800	148,978
2730000600	New York	1,511	80,571,790	126,735
3795000350	Pennsylvania	650	27,815,880	72,342
3800000800	Pennsylvania	1,600	100,763,230	241,426
4045000900	Indiana	1,062	59,604,720	147,606
4510001000	Alabama	910	54,170,170	68,824
4530000850	Texas	634	25,742,050	95,195
4740000300	Florida	1,136	71,443,680	250,963
4770003000	Kentucky	2,558	121,163,120	628,358
4770004100	Tennessee	2,660	128,536,880	572,320
4815000400	Ohio	1,831	132,159,990	254,335
4820001800	Michigan	2,462	141,227,620	433,206
5125000650	Missouri	1,150	47,372,990	67,997
5125000700	Missouri	1,100	51,037,800	176,480
5250001400	Virginia	845	42,656,150	68,606
5540000250	Missouri	527	20,774,340	108,149
Total		32,172	1,642,528,550	4,799,242
Average		1,341	68,436,690	199,968

TABLE 37. TWO POWER PLANTS SCRUBBING, PRODUCING, AND MARKETING ACID IN $0.50 ACFL RUN, BUT ALSO USING CLEAN FUEL

Plant No.	Location	MW	Btu scrubbed	Btu using clean fuel	Tons of acid
3455000400	Indiana	660	34,148,090	4,731,910	132,291
4805000200	Ohio	1,263	47,675,290	3,061,600	177,166
Total		1,923	81,823,380		309,457
Total ($0.50 run)		34,095	1,724,351,930		5,108,699

Production and sale of byproduct acid was the least-cost compliance strategy at all levels of clean fuel premium for seven of the power plants. This indicates that the combination of production costs and proximity to markets makes these plants the most stable candidates for use of recovery technology. They are presented graphically in Figure 24 and listed as follows:

Plant No.	Location	Incremental cost, $/ton acid[a]	Tons of acid
1395000250	North Carolina	0.00	105,209
3800000800	Pennsylvania	4.09	241,426
4510000100	Alabama	0.42	68,824
4740000300	Florida	16.72	250,963
4770003000	Kentucky	15.18	628,358
4770004100	Tennessee	10.01	572,320
4815000400	Ohio	7.02	254,335
Total			2,121,435

---

a. Additional unit cost of producing abatement acid as compared to limestone scrubbing.

However, at least two of these plants plan to use compliance methods that were not included as alternatives in the study.

A summary of model results for smelter and power plant sales to acid plant demand points for all model runs is outlined in Table 39. These results show the potential quantity of power plant acid in relation to the total market. At the $0.70/MBtu ACFL, the potential for production of acid (abatement capacity) at a cost below the ACFL premium fuel cost exceeded the market demand (sales) for the acid by 5 Mtons. All acid produced was marketed, but only the lowest cost producers could compete with existing supplies; the remainder used limestone scrubbing. At the $0.35/MBtu level, essentially all of the acid that could be produced economically compared to purchase of complying fuel was sold. The small differential in sales between the $0.50

TABLE 38. TWENTY-NINE POWER PLANTS SCRUBBING, PRODUCING, AND MARKETING ACID IN $0.70 ACFL RUN

Plant No.	Location	MW	Btu scrubbed	Tons of acid
0700000550	New York	1,200	50,142,240	75,016
0785000100	Illinois	616	24,933,140	126,448
0785000500	Illinois	590	23,955,530	77,549
0790000100	Illinois	602	29,939,960	96,692
1000000050	Texas	836	33,943,780	125,523
1095000200	Ohio	1,255	63,971,180	379,768
1115001300	Illinois	1,271	66,538,760	281,208
1395000250	North Carolina	2,286	99,576,110	105,209
1655000300	Florida	964	50,383,440	192,742
1790002550	Georgia	1,792	72,759,860	253,367
1790002800	Georgia	1,820	88,005,410	255,939
2455000250	Kentucky	1,011	56,196,800	148,978
2730000600	New York	1,511	80,571,790	126,735
3795000350	Pennsylvania	650	27,815,880	72,342
3800000800	Pennsylvania	1,600	100,763,230	241,426
3840000500	Pennsylvania	940	31,096,200	72,786
4045000900	Indiana	1,062	59,604,720	147,606
4510000100	Alabama	910	54,170,170	68,824
4530000850	Texas	634	25,742,050	95,195
4740000300	Florida	1,136	71,443,680	250,963
4770001900	Tennessee	1,482	72,402,030	301,246
4770002100	Tennessee	1,723	85,504,880	223,146
4770003000	Kentucky	2,558	121,163,120	628,358
4770004100	Tennessee	2,660	128,536,880	572,320
4815000400	Ohio	1,831	132,159,990	254,335
5125000650	Missouri	1,150	47,372,990	67,997
5125000700	Missouri	1,100	51,037,800	176,480
5250001400	Virginia	845	42,646,150	68,606
5540000250	Missouri	527	20,774,340	108,149
Total		36,562	1,813,152,110	5,594,953
Average		1,261	62,522,486	192,929

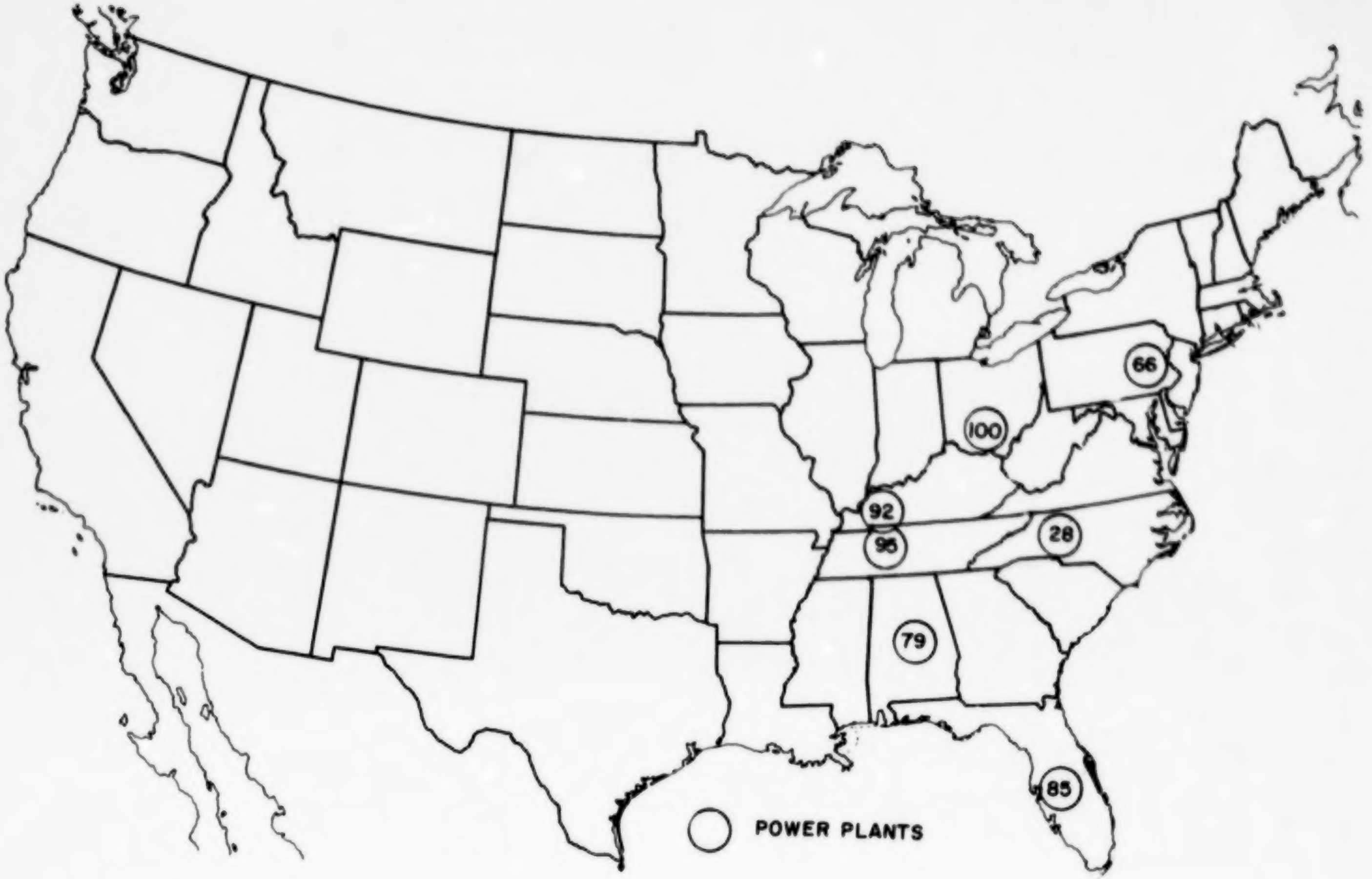
66
100
92
95
28
79
85
POWER PLANTS

Figure 24. Geographic distribution of the seven best power plant candidates for production and marketing of abatement H_2SO_4.

TABLE 39. SUMMARY OF MODEL RESULTS FOR SMELTERS AND POWER PLANT SALES TO ACID PLANT DEMAND POINTS

(ktons of H_2SO_4)

	ACFL, cents/MBtu			
	0	35	50	70
Eastern smelters				
Capacity	818	818	818	818
Sales	818	818	818	818
Demand points	15	13	12	14
Western smelters				
Capacity	738	738	738	738
Sales	738	738	594	498
Demand points	15	8	3	3
Canadian acid				
Capacity	200	200	200	200
Sales	200	200	200	200
Demand points	4	4	2	3
Total smelter acid capacity	1,756	1,756	1,756	1,756
Sales	1,756	1,756	1,612	1,516
Demand	32[a]	24[a]	16[a]	19[a]
Mixed demand points	11	13	15	13
Steam plants				
Capacity	-	2,635	8,497	10,758
Sales	-	2,554	5,108	5,595
Demand points	-	31[a]	57[a]	56[a]
Mixed demand points	-	9	16	14
Port Sulphur to H_2SO_4 plants				
Capacity	32,237	32,237	32,237	32,237
Sales	30,481	27,926	25,516	25,126
Demand points	69[a]	50[a]	35[a]	31[a]
Mixed demand points	11	8	5	4
Port Sulphur only	58	42	30	28

a. Steam plants and eastern and western smelters can supply a common demand point.

and \$0.70/MBtu level of ACFL indicates that the market for byproduct acid from power plants was nearly saturated at 5 Mtons, or approximately 15% of the total market. Further substitution of byproduct acid in the existing market would depend on substantial increase in the price of S; \$60 was assumed for the study.

An analysis of the distribution of byproduct acid is presented in the following section.

Operating Profile for Power Plants Associated with Compliance Strategies Proposed for 1978

A summary of the operating characteristics of the plants that are candidates for use of scrubbing and for production of abatement acid are outlined in Table 40.

In general, plants with a high scrubbing cost (and therefore good candidates for buying clean fuel) had small, old boilers with a low capacity factor, and burned fuel with a higher than average S content. Plants with low-to-average scrubbing costs tended to have the opposite characteristics, i.e., large, newer boilers with a higher capacity factor, and a lower S content fuel than the average burned by plants out of compliance.

Power plants that were the best candidates for production of acid were generally bigger, newer, and had a much higher capacity factor than scrubbing candidates in general. The best candidates had boilers more than three times as large as the average plant out of compliance. The following statements are generally true of the best candidates for acid scrubbing systems: (1) they burn coal; (2) the boilers have an average capacity factor of >60%; (3) the average boiler size is >600 MW (<15% of the boilers are smaller than 200 MW); and (4) they have very few old boilers (almost none >30 yr old), and most of their boilers are <10 yr old.

Two other factors not shown directly in Table 40 also have a significant impact in determining the best acid-producing candidates. Location is critical, since even though the economics of scrubbing to produce acid may be favorable, high transportation costs can offset the advantage of production cost. The emission standard promulgated for a given plant is important; unless large quantities of SO_2 removal are required (implying very low allowable emissions, very high emission levels, or a combination of both), scrubbing to produce acid is not usually the most economical method.

Changes in ACFL are more significant for scrubbing candidates that produce acid than for scrubbing candidates in general since market distribution is impacted as more and more plants are considered for acid scrubbing. Location factors are responsible for changing the mix as additional candidates are brought into the solution. For example, seven of the eight power plants producing acid in the \$0.35 ACFL run yielded demand points to relatively higher cost plants in the \$0.50 ACFL run. A further change in distribution pattern resulted in the \$0.70 ACFL run, 16 of 24 power plants producing acid in \$0.50 ACFL run yielded demand points to other plants even though all other characteristics were economically superior.

TABLE 40. OPERATING CHARACTERISTICS OF POWER PLANT CANDIDATES FOR USE OF SCRUBBING TECHNOLOGY

	Scrubbing cost, ¢/MBtu				Acid-producing plants at ACFL, ¢/MBtu		
	<35	<50	<70	>70	35	50	70
No. of power plants	19	74	116	71	8	26	29
No. of boilers	69	290	457	376	27	101	106
Total capacity, MW	25,642	84,716	109,518	23,081	17,581	40,383	43,259
Total fuel							
Coal, ktons	54,688	171,365	213,613	13,167	42,242	84,231	89,712
Coal, GBtu	1,242,134	3,888,782	4,825,282	299,793	975,606	1,912,380	2,007,277
Oil, kbbl	33,246	79,600	96,193	13,974	0	22,118	23,022
Oil, GBtu	204,605	494,105	598,090	88,810	0	137,750	143,263
Gas, Mft^3	10,173	14,976	28,274	79,965	0	3,213	463
Gas, GBtu	14,685	20,303	34,482	82,486	0	3,270	520
Average S content of coal, %	2.12	2.63	2.78	2.87	2.46	2.68	2.85
Average S content of oil, %	0.85	1.33	1.36	1.50	N/A	1.71	1.74
Average capacity factor, %	57.64	49.33	46.83	20.90	65.61	43.00	49.33
Average boiler generating capacity, MW	372	292	240	61	647	400	408
Age of boilers, %							
0-5	22	17	15	3	41	32	31
6-10	20	17	14	6	26	21	20
11-15	14	9	7	5	7	5	6
16-30	26	35	45	38	22	15	31
>30	18	22	19	48	4	27	12
Size of boilers, %							
<200	46	52	60	97	11	38	33
200-500	19	24	24	4	26	21	31
501-1000	28	22	15	1	44	36	31
>1000	7	2	1	0	19	5	5
Capacity factor of boilers, %							
<20	15	20	17	57	4	28	12
20-40	4	3	12	24	0	2	5
41-60	29	39	41	14	30	41	58
>60	52	38	30	5	66	29	25

RESULTS AND ANALYSIS OF DEMAND POINTS FOR ABATEMENT BYPRODUCT ACID

The demand analysis involves a detailed review of the 1978 acid plant operating profile assumed in this study. Each acid plant (90 total) has three alternative strategies for obtaining supplies: (1) buying elemental S from Port Sulphur via a marketing terminal and converting to H_2SO_4, (2) buying byproduct acid from a smelter, and (3) buying abatement acid from a steam plant. The model assumes that the acid plant will close down in the second and third strategies and buy abatement byproduct acid if it can be delivered equal to or below the avoidable cost of production in the existing plant. The feedstock analysis for the 90 acid plants considered is outlined as follows:

Feedstock Analysis for 90 Acid Plants

	ACFL, cents/MBtu			
	0	35	50	70
Buying Port Sulphur only	58	42	30	28
Buying from smelters only	21	11	1	5
Buying from steam plants only	0	22	41	41
Buying from Port Sulphur and smelters	11	6	2	1
Buying from Port Sulphur and steam plants	0	2	3	2
Buying from Port Sulphur and smelters and steam plants	0	0	0	1
Buying from smelters and steam plants	0	7	13	12
Total acid plants	90	90	90	90

The specific plants associated with each purchase option identified in the model run in accordance with the above tabulation are outlined in Appendix N, Tables 1-12. The geographic distribution of acid plants buying elemental S only versus plants purchasing abatement byproduct acid is presented in Figure 25.

Best Candidates for Purchasing Abatement Byproduct Acid

Four significant factors that affect the purchase of abatement acid by current producers of H_2SO_4 in this study are listed as follows: (1) size, (2) age, (3) compliance with clean air standards, and (4) location. The first three factors are reflected in the avoidable cost of production. The location factor relates to transport cost.

Acid plants considered in the study range in size from 6,000 tons/yr to 2,260,000 tons/yr. Size is a critical factor in the solution results. No plant larger than 500,000 tons/yr (28 plants) was a potential buyer of abatement acid, while all plants <75,000 tons/yr (24 plants) were potential buyers of abatement acid in the model solutions (see Appendix O, Table 1).

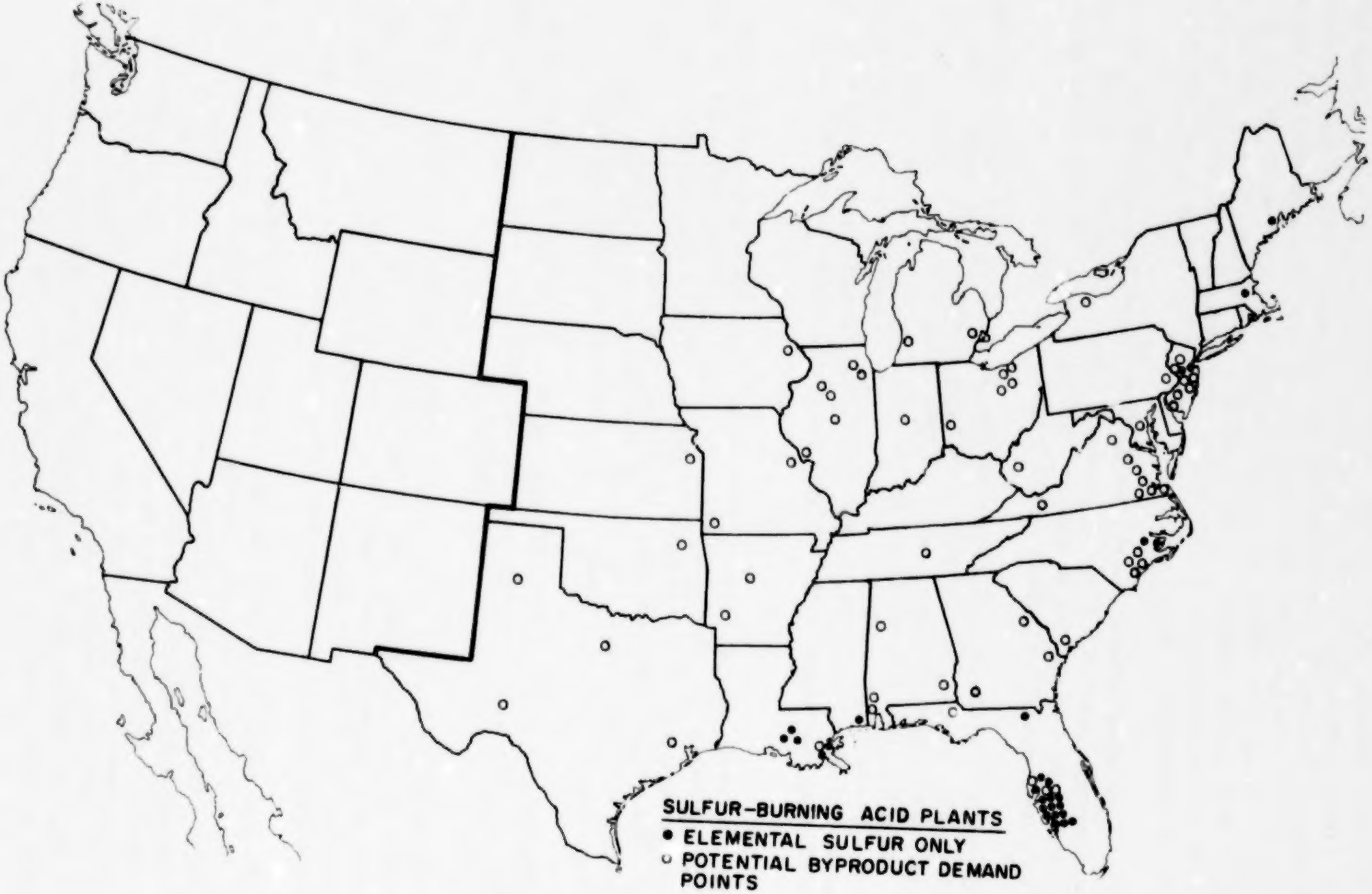
SULFUR-BURNING ACID PLANTS
● ELEMENTAL SULFUR ONLY
○ POTENTIAL BYPRODUCT DEMAND POINTS

Figure 25. Geographic distribution of S-burning acid plants (1978).

Size and age parameters are somewhat related since technological advancements in 1960 made it feasible to build much larger H_2SO_4-producing facilities (6000 ton/day units). Most of the larger plants are located on the Gulf Coast in close proximity to the S supplies. Acid plants built after 1960 have an average production of 1680 tons/day and represent 49% of the total number of plants in the study; they represent 76% of the total production capacity of all plants. About one third of the abatement byproduct acid in the $0.70 ACFL model run was delivered to these plants and replaced only 10% of their total production capacity. A listing of the ownership of plants by size is outlined in Appendix O; plants that purchase acid in the model run are shown.

The older plants built prior to 1960 include 46 plants with 24% of the total production capacity for all plants. The average size is 520 tons/day. These plants use 67% of the abatement byproduct acid in the $0.70 ACFL model run which replaces 64% of their total production capacity.

Appendix P presents a listing of the 20 acid plants which are projected to operate out of compliance with clean air standards in 1978. The plants that are purchasing abatement acid in the model runs are identified in Table P-1. As the ACFL is raised an increasing number of these plants buy abatement acid because the economic incentive for producing acid at power plants increases and production from more favorable locations is available. Only 30% are purchasing abatement acid at the zero ACFL where only smelter acid is marketed.

An analysis of the size of firm associated with production capacity is shown in Appendix O. There are 42 firms with 90 S-burning acid plants with production capacity of 32,227,000 tons/yr. The 15 largest firms have 48 acid plants (54% of all plants) equal to 80% of the total production capacity of all plants. These plants buy 48% of the abatement byproduct acid in the $0.70 ACFL run, but it replaces only 13% of their production capacity.

The 27 small firms have 42 acid plants equal to 20% of total production capacity of all plants. They buy 52% of abatement byproduct acid which replaces 64% of their production capacity.

Table 41 identifies acid plants that purchase abatement byproduct acid in more than one of the model runs at given ACFL. Most of such plants are older, smaller, and generally more remotely located from the Gulf Coast supplies of S as compared to the total population, but there are exceptions. Unique location advantage for across-the-fence operation can preempt other factors.

In the model runs, all the acid produced by a specific power plant was sold, but the supply did not exactly equal the demand at the points of use. Therefore, the incremental demand was met through production of acid from S. This incremental amount represents an additional quantity of byproduct acid that could be sold at the values calculated in the model. Specific power plants and smelters that could supply this additional demand if production could be increased (higher load factor or higher S coal), were identified and are listed in Tables 13-16 of Appendix N. A summation of the additional amounts at each level of clean fuel premium is as follows:

TABLE 41. ACID PLANTS BUYING ABATEMENT ACID IN MODEL RUNS

ONE ACID PLANT BOUGHT BYPRODUCT ACID IN THE SMELTERS ONLY RUN AND IN THE 50c AND 70c ACFL POWER PLANT RUNS. DID NOT BUY BYPRODUCT ACID IN THE 35c RUN.

No.	Company	Location		Capacity	Year	Avoidable production cost, $/ton of acid
114	U.S. Industrial Chem	Desoto	KS	105,000	1940	40.29
17 ACID PLANTS BUYING ACID AT $.35, $.50, AND $.70 BUT NOT IN SMELTERS ONLY RUN						
10	Allied Chemical	Nitro	WV	135,000	1940	38.03
13	Allied Chemical	Front Royal	VA	160,000	1945	35.94
20	American Cynamid	Hamilton	OH	95,000	1967	36.76
28	Army Ammunition Plant	Radford	VA	212,000	1940	35.95
33	Borden Chemical	Norfolk	VA	80,000	1937	38.06
46	E. I. Dupont	Richmond	VA	90,000	1946	37.27
48	E. I. Dupont	North Bend	OH	175,000	1956	42.41
49	E. I. Dupont	Deepwater	NJ	125,000	1937	36.21
50	E. I. Dupont	Cleveland	OH	200,000	1937	43.25
61	W. R. Grace	Charleston	SC	42,000	1937	42.51
70	LJ & M LaPlace	Edison	NJ	75,000	1967	34.40
96	Royster Company	Mulberry	FL	325,000	1967	35.60
102	Stauffer Chemicals	LeMoyne	AL	250,000	1957	35.06
109	Swift Chemicals	Norfolk	VA	35,000	1946	44.28
116	USS Agri-Chem	Navassa	NC	70,000	1967	38.72
119	Weaver Fertilizer	Norfolk	VA	35,000	1967	44.55
120	Acme (Wright) Fertilizer	Acme	NC	48,000	1968	36.22
12 ACID PLANTS BUYING BYPRODUCT ACID AT $.50 AND $.70 BUT NOT AT $.35						
11	Allied Chemical	Hopewell	VA	200,000	1965	35.50
40	Cities Service	Augusta	GA	125,000	1967	32.51
53	Essex Chemical	Newark	NJ	180,000	1956	33.20
56	Gardinier	Tampa	FL	450,000	1937	34.17
62	W. R. Grace	Bartow	FL	320,000	1960	33.81
74	Mobil Oil	Depue	IL	420,000	1967	31.19
77	Monsanto Company	El Dorado	AR	100,000	1960	35.03
83	Occidental Ag Chem	Plainview	TX	100,000	1963	36.84
114	U.S. Industrial Chem	Desoto	KS	105,000	1940	40.29
131	U.S. Industrial Chem	Tuscola	IL	170,000	1975	32.12
134	E. I. Dupont	Linden	NJ	325,000	1937	32.78
136	USS Agri Chem	Wilmington	NC	70,000	1968	33.94
2 ACID PLANTS BUYING BYPRODUCT ACID AT $.70 BUT NOT AT $.35 OR $.50						
18	American Cynamid	Savannah	GA	216,000	1967	29.80
86	Olin Corporation	Baltimore	MD	350,000	1941	32.48

Additional Byproduct Acid Production and Sales to Acid Plants Without Changing the Optimal Solutions in Each Model Run

Cents/MBtu	Tons
0	1,283,000
35	706,565
50	668,623
70	632,282

The model could be refined to incorporate those additional quantities, but the impact on validity of conclusions drawn from the study does not justify the significant added cost. The capability to identify the supply points and potential quantities as was done in the study is adequate.

SUPPLEMENTARY ANALYSIS

Summary of SO_2 Emissions Control Strategies to Meet Compliance

Table 42 summarizes the reduction in SO_2 emissions by each compliance strategy for all of the 187 power plants that were projected to be out of compliance in 1978. SO_2 control by clean fuel strategy accounts only for the reduction required by SIP standards. Use of scrubbing technology reduces the emissions further than that required by the regulations because the removal efficiency and amount of gas treated cannot be practically matched with the standard. A constant removal efficiency was assumed and gas volume was based on increments of standardized-size scrubber modules. The column labeled "excess removed by scrubbing" shows the total amount for both limestone and MgO scrubbing.

Clean Fuel Demand Curve

The use of clean fuel as an alternative to scrubbing can be presented graphically in the form of a demand curve. This demand curve is estimated by plotting limestone scrubbing cost for all power plant boilers or combinations of boilers from highest to lowest cost versus the reduction in emission accumulated as shown in Figure 26. Scrubbing cost is presented in cents/MBtu and is the maximum premium that can be paid for complying fuel.

At the upper end of the curve there are a few small power plants that only exceed SIP requirements by a small amount yet the law requires compliance by either an FGD system or the use of clean fuel. In this instance the power plant can pay a very high premium for clean fuel as an alternative to scrubbing. In the flat part of the curve the economies to scale associated with large scrubber systems or large power plants burning medium- to high-S coal reduces the unit cost of scrubbing to the point that a relatively lower premium can be paid for clean fuel as an alternative to scrubbing. As the cost of clean fuel

TABLE 42. 1978 STRATEGIES SELECTED FOR REDUCING EMISSIONS

(ktons/yr H_2SO_4)

ACFL, cents/MBtu	Total by scrubbing	Amount required by SIP	By MgO scrubbing	By limestone scrubbing	By using clean fuel	Total reduction	Excess removed by scrubbing
∞	13,598	9,912	-	-	-	-	-
70	12,583	9,211	5,595	6,988	700	13,284	3,371
50	9,503	6,788	5,108	4,394	3,123	12,627	2,714
35	2,885	1,919	2,554	330	7,993	10,878	965
0	0	0	0	0	9,912	9,912	0

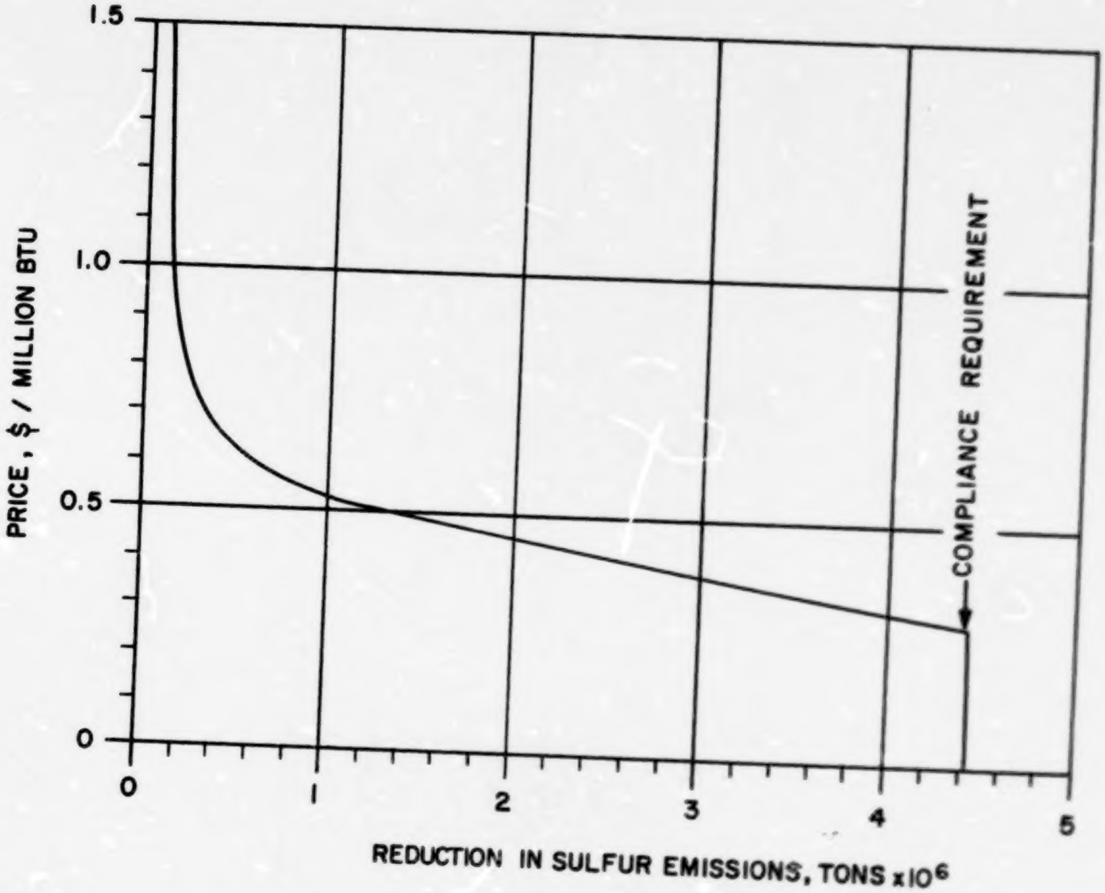

Figure 26. Clean fuel demand curve - all plants (1978).

is reduced the more clean fuel is used in lieu of scrubbing. No scrubbing would occur ≤$0.25/MBtu heat input based on the costs of technology used in this study.

Power Plant Supply Curve Based on Incremental Cost for Production of Abatement Acid

The incremental cost of production for power plants producing acid as compared to limestone scrubbing in each of the ACFL model runs can be presented in graphic form as a supply curve by plotting incremental cost from lowest to highest versus the accumulating acid production for each increment. This is presented in Figures 27, 28, and 29. The incremental cost represents the net revenue required to justify production of acid. The average of the incremental cost is calculated at $11/ton for the $0.35 ACFL, $10.65/ton for the $0.50 ACFL, and $10.97/ton for the $0.70 ACFL.

Transportation Cost Analysis

The transportation cost analysis is outlined in the following tabulation:

	ktons of H_2SO_4					
ACFL, cents/MBtu	Power plants	U.S. smelters	Canadian smelters	Total	Transport cost, $	$/ton
0	-	1,556	200	1,756	13,513	7.70
35	2,623	1,556	200	4,379	41,311	9.43
50	5,370	1,412	200	6,982	64,371	9.22
70	6,069	1,312	200	7,585	72,919	9.61

The data show that as the volume of acid increases the total costs of transportation increases proportionately. The fairly constant unit cost of transportation results from change in distribution pattern as additional producers supply demand points with location advantages so that total costs are minimized. This is illustrated by the fact that the demand points changed for 16 out of 24 power plants in the $0.70/MBtu ACFL run as compared to the $0.50/MBtu run, and only two additional demand points were needed for the five additional power plant supply points.

Impact of Barge Transportation

Barge transport was utilized in the model to handle deliveries of molten S from Gulf Coast to marketing terminals where truck or rail transport was used to reach acid plants, but only rail transportation was used to distribute abatement acid. Numerous power plants are located on navigable waterways. Barge transport would be a viable option for shipping byproduct acid from these plants. Barge transportation of acid could be included in the model. However, rates are not standard and a major effort would be required to estimate negotiated rates for all points.

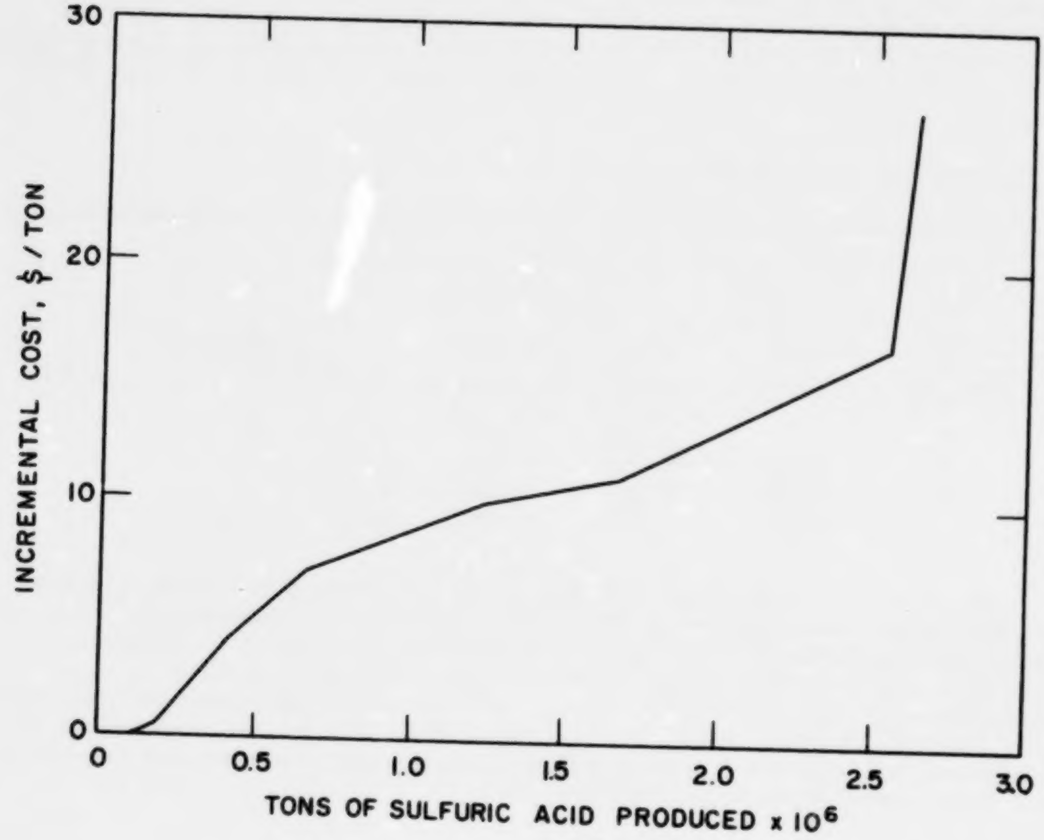

Figure 27. Abatement acid supply curve for $0.35 ACFL model run.

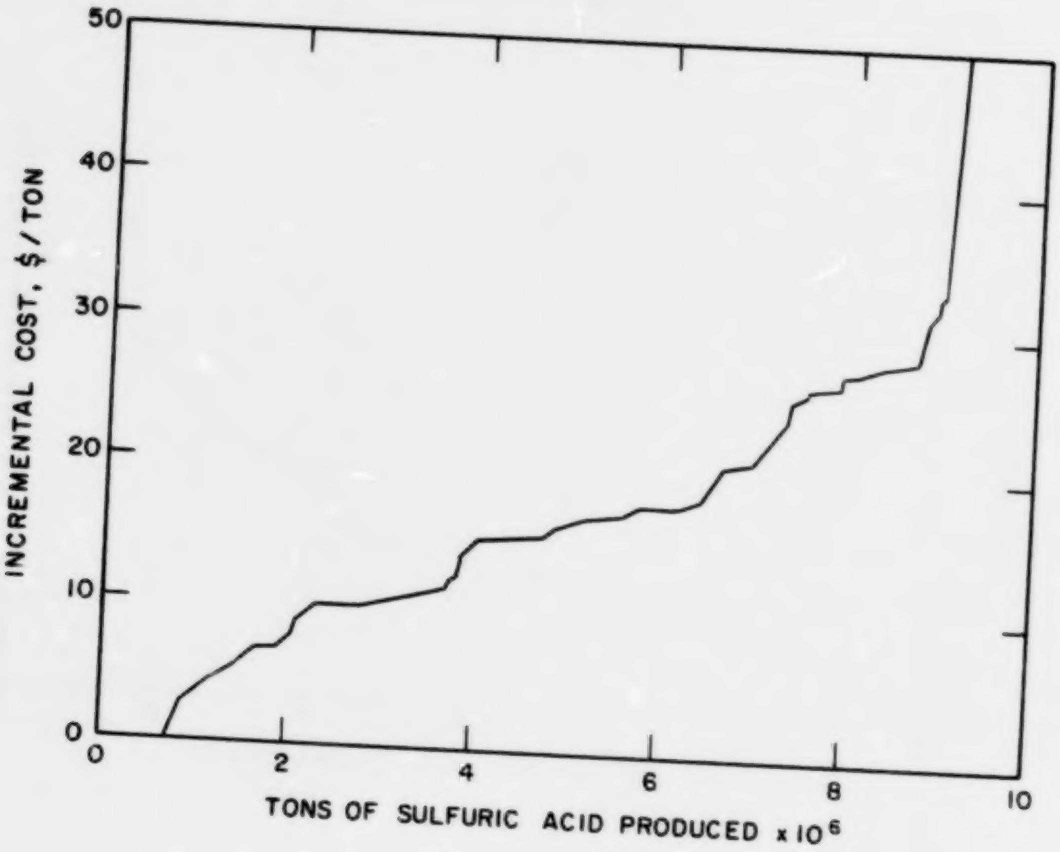

Figure 28. Abatement acid supply curve for $0.50 ACFL model run.

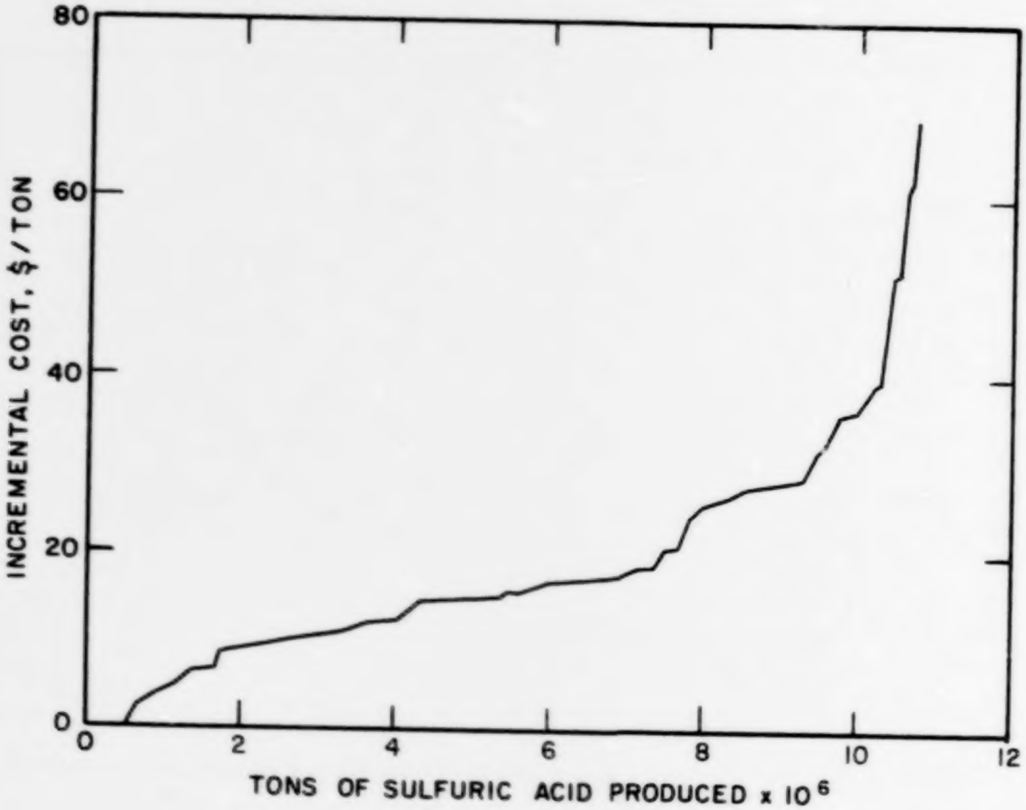

Figure 29. Abatement acid supply curve for $0.70 ACFL model run.

An estimate of potential savings by barge shipments was prepared for three candidates for MgO-acid scrubbing that are located on the inland waterway system.

Rail and Barge Shipments from Power Plants to 42 Acid Plants on the Inland Waterway System

FPC No.	Location	Tons shipped	Rate/ton	Rail, $	Barge, $
4770003000	Kentucky	628,358	Average	19.22	16.63
			Highest	30.28	32.93
			Lowest	10.20	8.64
4770004100	Tennessee	572,320	Average	19.58	16.06
			Highest	32.05	32.03
			Lowest	10.20	7.89
4815000400	Ohio	254,355	Average	26.43	19.84
			Highest	47.09	39.37
			Lowest	11.09	7.39

The potential savings for utilizing barge shipment in three model runs, \$0.35, \$0.50, and \$0.70/MBtu ACFL, are presented in Table 43.

The net reduction in transport cost resulting from barge transport for each of the model runs is listed as follows:

	ACFL, cents/MBtu		
	35	50	70
Reduced cost, $	483,101	644,931	725,308

However, these results do not necessarily represent optimal solution of a linear programing model, even for the three plants selected. If the model were actually run with the barge transport option the optimum production and distribution of abatement acid could change significantly. The only conclusion that can be made in the absence of such a model run is that transportation costs would be lower. Therefore, the potential savings to both industries would be greater as compared to model solutions presented in this study.

Sensitivity of the S Price

One of the key inputs in the analysis of the potential market for abatement byproduct acid is the price of elemental S. All of the results of this study are based on S price of \$60/ton f.o.b. Port Sulphur. A \$20.00 decrease in the price of S lowers the avoidable cost of production for H_2SO_4 at each respective acid plant by \$6.11/ton of acid produced. This lower price structure would reduce the quantity of both byproduct smelter acid as well as

TABLE 43. COST REDUCTION BY BARGE SHIPMENT

FPC number	Location	Reduction by barge	Tons	Reduced cost
		At 35¢/M ACFL		
2. 4770003000	Kentucky			
10 Allied Chemicals		3.03/ton	37,670	114,140.00
3. 4770004100	Tennessee			
16 American Cyanamid		0.28/ton	26,000	7,280.00
4. 4815000400	Ohio			
10 Allied Chemical		3.70/ton	97,330	360,111.00
52 Eastman Kodak		0.26/ton	6,000	1,560.00
		At 50¢/M ACFL		
2. 4770003000	Kentucky			
96 Royster		0.26/ton	134,350	34,931.00
3. 4770004100	Tennessee			
126 American Cyanamid		2.21/ton	50,000	110,500.00
4. 4815000400	Ohio			
10 Allied Chemical		3.70/ton	135,000	499,500.00
		At 70¢/M ACFL		
2. 4770003000	Kentucky			
62 W. R. Grace		0.26/ton	239,600	62,296.00
96 Royster		0.26/ton	141,250	36,725.00
3. 4770004100	Tennessee			
96 Royster		0.69/ton	183,750	126,787.00
4. 4815000400	Ohio			
10 Allied Chemical		3.70/ton	135,000	499,500.00

the abatement acid from power plants that can be marketed in the model. An estimate of the extent of reduction is shown in Table 44. The specific power plants and acid plants affected are presented in Appendix Q.

The estimates were based on manual calculations rather than a complete model run because the $40 S price is arbitrary and was selected only to show the effect of price. The above analysis shows that the quantity of abatement byproduct acid that could be sold in the existing market would be reduced by a significant amount.

OTHER USES OF THE MODEL

The development of data bases and programs for use of the model to predict byproduct market potential resulted in capability to perform other highly relevant calculations.

Investment Costs

The scrubber cost generator may be used to estimate the investment of alternative scrubbing systems for all existing and planned power plants. In this study, costs were estimated for limestone, MgO, and Wellman-Lord/Allied scrubbing systems for all plants projected to be out of compliance in 1978. For use in the study, relativity of investment costs was the primary interest. However, the input cost data could be refined to reflect special design considerations for specific plants to improve the accuracy of estimates not only for the plants included in this study but for the total current and future population. This capability would be particularly helpful in evaluating conversion from gas or oil to coal. Moreover, the alternative methods for compliance could be expanded to include other scrubbing systems, coal cleaning, production of clean fuels from coal, or other advanced technology for use of coal.

An example of use of the model to estimate investment costs is shown below in the cumulative total capital required for limestone scrubbing for the 187 plants considered in the study.

ACFL, cents/MBtu	Investment for scrubbing, $
∞	6,937,543,000
70	5,501,613,000
50	4,058,091,000
35	1,079,165,000

Operating Costs

The scrubber cost generator can also be used to estimate operating costs with the same degree of flexibility as discussed in the investment cost description. For this study, only the first year operating costs were estimated for the three scrubbing methods at each plant out of compliance. If

TABLE 44. EFFECT OF $20 REDUCTION IN S PRICE ON SUPPLY AND DEMAND FOR BYPRODUCT ACID

Reductions			Tons of acid
At 35¢ clean fuel alternative			
Supply:	2 power plants		246,311
	4 smelters		437,000
		Total	683,000
Demand:	6 acid plants		683,000
At 50¢ clean fuel alternatives			
Supply:	6 power plants		639,722
	2 smelters		498,000
		Total	1,137,722
Demand:	10 acid plants		1,137,722
At 70¢ clean fuel level			
Supply:	8 power plants		939,163
	2 smelters		417,000
		Total	1,356,163
Demand:	10 acid plants		1,356,163

the projected load factors over the life of the power plants were available, the lifetime operating costs could be developed. This information is necessary to estimate revenue requirements from present worth costs to cover the additional cost of operation, including amortization of investment. A major revision of the model would be required to estimate revenue requirements. However, a program in Fortran language is available from another study.

The estimated total first year operating costs for use of limestone scrubbing and clean fuel at the 187 plants defined earlier is as follows:

ACFL, cents/MBtu	Operating cost, $		
	Scrubbing	Clean fuel	Total
∞	2,886,245,000	0	2,886,245,000
70	2,037,721,000	267,351,000	2,305,072,000
50	1,513,241,000	636,280,000	2,149,521,000
35	406,877,000	1,225,907,000	1,632,784,000

Use of clean fuel at some of the plants compared to scrubbing at all plants results in savings to the utility industry of:

ACFL, cents/MBtu	Savings, $
70	561,172,000
50	716,723,000
35	1,233,461,000

Change in Regulations

The procedure for evaluating compliance status based on applicable standards and FPC projection of fuel characteristics may be used to estimate the effect of changing emission standards on the cost of compliance. This study was based on the SIP regulations that were in effect as of June 1976. The program would be useful in evaluating the cost use benefit of alternative standards, provided that valid information could be developed for projecting costs for these processes at various SO_2 removal efficiencies. Also, information is needed on economic effect of various emission rates.

Evaluation of Other Abatement Products

The model can be modified to include byproducts other than S and H_2SO_4 and to evaluate potential for restructuring end use markets to take into account location advantages.

Use of Transportation Model

The transportation model that was developed to distribute byproduct acid from supply points to areas of use is a sophisticated program that has potential for extensive use. The model calculates actual rate-base mileage between any two points on the established railway network. For this study, tariffs were incorporated for H_2SO_4 movements. Available tariffs for any other commodity could be incorporated to calculate actual transportation costs between any two points. The model can be used to estimate cost of rail shipments for any of the materials that may be needed in compliance programs including coal, raw materials for scrubbing systems, byproducts for disposal or use, clean fuels derived from coal, and equipment. Usefulness of the model in other areas of the industrial community is obvious.

Truck and barge transportation costs are not as easily defined as rail shipments but meaningful approximation could be developed to extend the capability of the model. A significant amount of work would be necessary.

Social Cost Consideration

An important conceptual use of the marketing model is shown in Figure 30. This figure is the classical presentation of economic benefit to consumers of a product (consumer surplus) and the benefit to the producer (producer surplus). The use of the term surplus indicates that the action represented results in a reduction in resources required to match the supply with the demand. The combined economic benefit is defined as net social gain. The area under the demand curve DD' out to supply quantity Q (DRQS) is the total gain to consumers (acid plants) from the purchase of Q tons of H_2SO_4. (It should be recognized that marketers cannot give preferential treatment to certain customers because of antitrust laws; therefore, in the optimum solution, all customers pay the same price for abatement acid.) Consumers pay a total of P $/ton for Q tons that results in a total cost represented by the rectangle (PSQR). Similarly this same total revenue pays for producing acid at the power plants where the total cost for production is the area (RSQ) below the supply curve SS' out to supply quantity Q. Consumer surplus is the indicated area (DPR). Producer surplus is the area below P and above the supply curve as indicated (PRS). At equilibrium the most marginal consumer and producer neither gain nor lose, but all others in the solution have an economic advantage; net social gain is the total savings by both. Methodology used in this study does not address division of net social gain between producer and consumer. It is assumed this will be determined in the market place.

The above theory can be related to results of the study. The linear programing model summarized the least-cost solutions associated with each model run. The results are outlined in Table 45 entitled "Total Cost of Acid Production for Model Runs." The reduction in total cost of acid is the net social gain that results from productive use of abatement byproduct acid in the existing market. Distribution of the savings between the utility industry and the acid industry will depend on negotiations between the two.

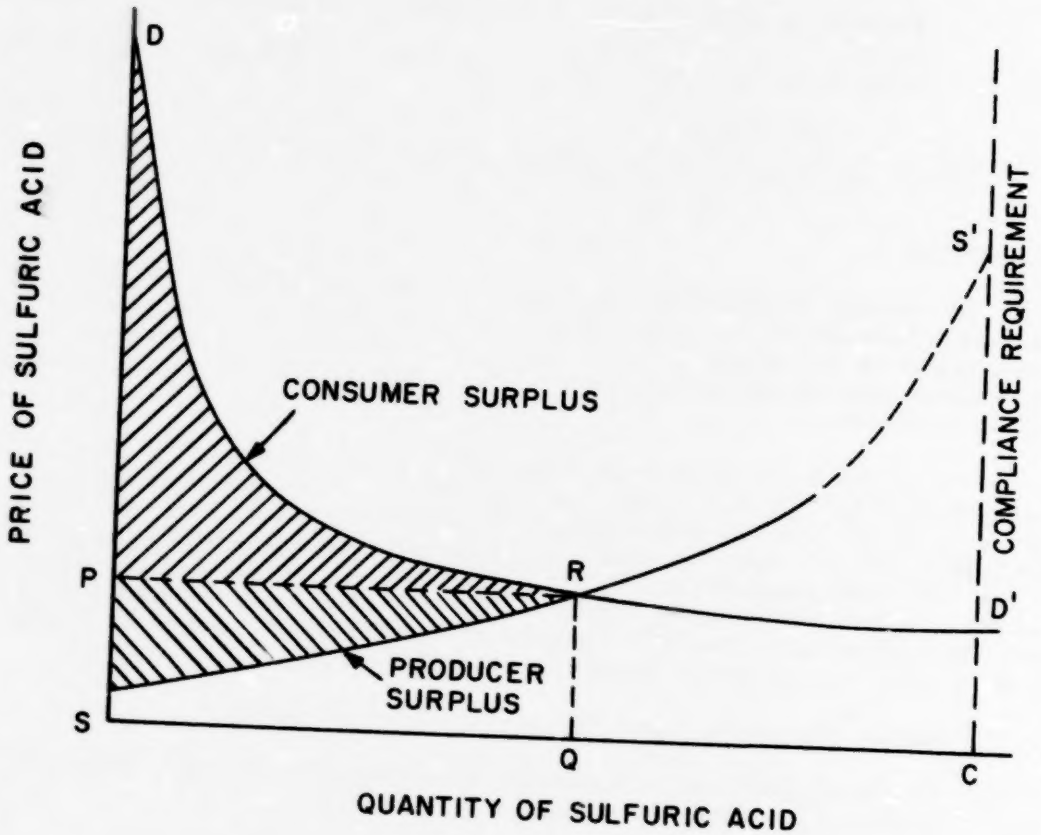

Figure 30. Conceptual demand curve for H_2SO_4 and supply curve for abatement production.

TABLE 45. TOTAL COST OF ACID PRODUCTION FOR MODEL RUNS

Acid industry cost, $	ACFL, cents/MBtu		
	35	50	70
Acid from S	965,377,000	965,377,000	965,377,000
Byproduct acid + acid from S	885,043,000	846,421,000	842,500,000
Reduction in cost of acid	80,335,000	118,956,000	122,887,000
Tons of acid utilized	4,379,000	6,982,000	7,585,000
Total from steam plants	2,623,000	5,370,000	6,069,000
Total from smelters	1,756,000	1,612,000	1,516,000
$/ton saving	18.34	17.04	16.20

CONCLUSIONS

The overall objective of the study, to identify potential markets for abatement byproducts from electric utility FGD systems, was accomplished. In the conduct of the study, a large volume of useful data was assembled and procedures were developed for use of the information in the market studies and in related work.

The entire U.S. electric utility industry was characterized from FPC data with respect to fuel type, capacity, load factors, and SO_2 emission rates. Out of a total of 3,382 generating units at 800 power stations, 833 boilers at 187 power stations were projected to be out of compliance with current applicable emissions regulations in 1978. The total SO_2 emissions from these 187 plants was equivalent to 17.5 Mtons of H_2SO_4; total H_2SO_4 consumption in the U.S. was estimated to be 32.2 Mtons in 1978. Therefore, the total market is nearly twice the potential byproduct production.

A market simulation model was developed to estimate:

1. Potential quantity of byproduct resulting from recovery being the least-cost compliance method
2. Quantity of byproduct could be sold in a competitive market environment
3. Best power plant candidates for production
4. Most likely consumption points

Through use of a scrubber cost generating model, it was determined that limestone scrubbing is generally the least-cost scrubbing method when credit for byproduct sales is not included and when credit is applied, production of byproducts becomes competitive. Costs for production of S by the Wellman-Lord/Allied process were higher in all cases studied than production of H_2SO_4. Projected savings in distribution costs for S compared to H_2SO_4 did not offset the incremental production costs. Costs for use of the Wellman-Lord/Allied technology will be more clearly defined during the current full-scale demonstration, partially funded by EPA, at the Mitchell Station of the Northern Indiana Public Service Company. Revised information will be included in the model. Also, EPA is currently sponsoring work with ESEERCO and Niagara Mohawk to develop the Atomics International process for producing S from SO_2 in stack gas. This technology and other work involving use of solid reductants could lead to lower costs for production of S as an alternative to producing H_2SO_4. Several factors that are difficult to incorporate into a generalized economic model could have a significant influence on the choice of byproducts. The incentive for production of S is high because it is a safe, noncorrosive, convenient material to handle, and can be easily stockpiled for long periods of time at relatively low cost. Because of the latter advantage, S could be incorporated more easily into the existing market. Moreover, fluctuations in market demand could be met with less impact to both the producer and consumer. It is likely that a mix of marketable byproducts will ultimately provide the least cost compliance with SO_2 regulations in the utility industry. Technology for production of S should be fully developed so that the choice is available and so that accurate information is available for cost comparisons with other methods of control.

An alternative to use of scrubbing was provided by comparing the cost of scrubbing with selected values of premium cost of complying fuel. When the clean fuel premium was set at \$0.70/MBtu, the mix of least-cost compliance methods was:

Purchase complying fuel	71 plants
Use limestone scrubbing	87 plants
Produce byproduct acid	29 plants

The amount of acid produced and marketed totaled approximately 5.6 Mtons; an additional 5 Mtons could have been produced at a lower cost than the alternative compliance method selected but could not be sold in competition with acid produced from elemental S priced at \$60/ton. The simulation model was designed to allow the nonferrous smelter industry to compete with the utility industry for byproduct markets. The total byproduct acid supplied from both industries was 7.11 Mtons or 22% of the total H_2SO_4 market.

Power plants that were the best candidates for production of byproduct acid were generally bigger, newer plants with high load factors. The distinctive characteristics were:

1. Most boilers <10 yr old
2. Average size about 600 MW (<15% smaller than 200 MW)
3. Average capacity factor about 60%

The average load factor for potential acid-producing plants was more than three times as high as the average of all plants considered.

When the clean fuel premium was set at \$0.50/MBtu, the amount of acid supplied by the utility industry was reduced to 5.1 Mtons. When the value of elemental S was reduced from \$60 to \$40/ton, the amount of byproduct acid that could be sold to replace production from existing conventional sources was reduced from 5.6 to 4.2 Mtons.

Abatement acid produced in the model run from the utility industry at the \$0.70/MBtu clean fuel premium was distributed to 55 different demand points in 23 states. The current supply that was replaced by byproduct acid was generally from smaller, older plants remotely located from the elemental S production points. The larger, more efficient plants generally can produce acid at costs lower than the delivered cost of abatement byproducts. However, there are exceptions. Savings in transportation cost because of location advantage can offset production cost differential.

The model assumed distribution of byproduct acid by rail shipment. Several of the potential producers are located on navigable waterways and could use barge transportation. As an example of possible savings on shipment costs, estimates were made for barge shipments of selected production totaling 700,000 tons. The cost differential between rail and barge transportation totaled \$725,000 or about \$1/ton of acid. This potential savings is 11% of the average transport cost.

The results of the study show that a significant amount of byproduct acid produced by the utility industry could be incorporated in an orderly manner into existing H_2SO_4 markets. The control of SO_2 emissions in the utility industry through use of recovery technology could contribute 56% of the estimated total reduction needed for the industry to be in compliance. Further use of recovery technology will depend primarily on substantial increases in elemental S prices which are difficult to predict. Reduction in the cost of control technology would also increase the potential for increased production of byproducts, but the costs are not likely to improve significantly. The costs may be understated in this study because a 1975 basis (escalated to 1978) was used for the investment and operating cost estimates. Reduction in transportation costs is a more realistic possibility for improving economics of marketing byproduct acid. Higher levels of clean fuel premium would not affect the results since the acid supply at the maximum value studied exceeded the demand. It should be emphasized that some of the plants that are good candidates for use of recovery technology may be implementing other compliance plans.

The development of data bases and programs for use of the model to predict byproduct market potential resulted in capability to perform other highly relevant calculations.

The scrubber cost generator may be used to estimate the investment of alternative scrubbing systems for all existing and planned power plants. In this study, costs were estimated for limestone, MgO, and sodium sulfite (Na_2SO_3) scrubbing systems for all plants projected to be out of compliance in 1978. For use in the study, relativity of investment costs was the primary interest. However, the input cost data could be refined to reflect special design considerations for specific plants to improve the accuracy of estimates not only for the plants included in this study but for the total current and future population. This capability would be particularly helpful in evaluating conversion from gas or oil to coal. Moreover, the alternative methods for compliance could be expanded to include other scrubbing systems, coal cleaning, production of clean fuels from coal, or other advanced technology for use of coal.

The scrubber cost generator can also be used to estimate operating costs with the same degree of flexibility as discussed in the investment cost description. For this study, only the first year operating costs were estimated for the three scrubbing methods at each plant out of compliance. If the projected load factors over the life of the power plants were available, the lifetime operating costs could be developed. This information is necessary to estimate revenue requirements from present worth costs to cover the additional cost of operation, including amortization of investment. A major revision of the model would be required to estimate revenue requirements.

The procedure for evaluating compliance status based on applicable standards and FPC projection of fuel characteristics may be used to estimate the effect of changing emission standards on the cost of compliance. This study was based on the SIP regulations that were in effect as of June 1976. The program would be useful in evaluating the cost to benefit ratio of alternative standards, provided that valid information could be developed for projecting costs for these processes at various SO_2 removal efficiencies. Also, information is needed on economic effect of various emission rates.

The model can be modified to include byproducts other than S and H_2SO_4 and to evaluate potential for restructuring end use markets to take into account location advantages.

The transportation model that was developed to distribute byproduct acid from supply points to areas of use is a sophisticated program that has potential for extensive use. The model calculates actual, legal mileage between any two points on the established railway network. For this study, tariffs were incorporated for H_2SO_4 movements. Available tariffs for any other commodity could be incorporated to calculate actual transportation costs between any two points. The model can be used to estimate cost of rail shipments for any of the materials that may be needed in compliance programs including coal, raw materials for scrubbing systems, byproducts for disposal or use, clean fuels derived from coal, and equipment. Usefulness of the model in other areas of the industrial community is obvious.

An important finding was that while long-run competitive equilibrium solutions predict what may happen in competitive markets they do not identify net social gain. The linear programing model solutions present a running account of minimum cost solutions associated with each model run for both industries. The savings to both industries at the $0.70/MBtu clean fuel premium run resulting from absorption of abatement byproduct acid in the existing market amounted to $122,877,000 or $16.20/ton of acid utilized.

RECOMMENDATIONS

Information on current compliance programs for existing power plants and for additional planned capacity was not available during the period of this study. The results of the work show that the potential for use of recovery technology is good and the initial follow-on work should focus on plants where compliance alternatives are still flexible. A survey of compliance plans should be carried out and the option of producing byproduct acid should be evaluated by incorporating specific information on those plants into the program data base. This evaluation would be particularly helpful in the planning process for future coal-fired power plants or for those that may be required to convert from gas or oil to coal.

In order for the program to remain meaningful, the data bases will have to be updated periodically. The period should be keyed to the annual FPC report on the utility industry. Investment and operating cost data on alternative FGD technology should be refined to permit more accurate estimation of emission control cost for specific plants and for the overall power industry.

Use of the simulation models and the associated data bases is presently limited to TVA personnel familiar with the complex program. The program is being documented and included along with procedures in a users manual that, as a minimum, will define the capability of the system. If the demand for use of any part of the program justifies the expense, the files can be maintained online so that qualified users can access the system through time-sharing facilities.

An extension of the program is planned, subject to availability of funds, to evaluate effect of product end use pattern on market potential for byproducts. For example, availability of byproduct H_2SO_4 in the Midwest could favor production of fertilizer materials near the point of use rather than near the location of traditional raw materials.

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APPENDIX A

BASIC SYSTEM FLOW DIAGRAM

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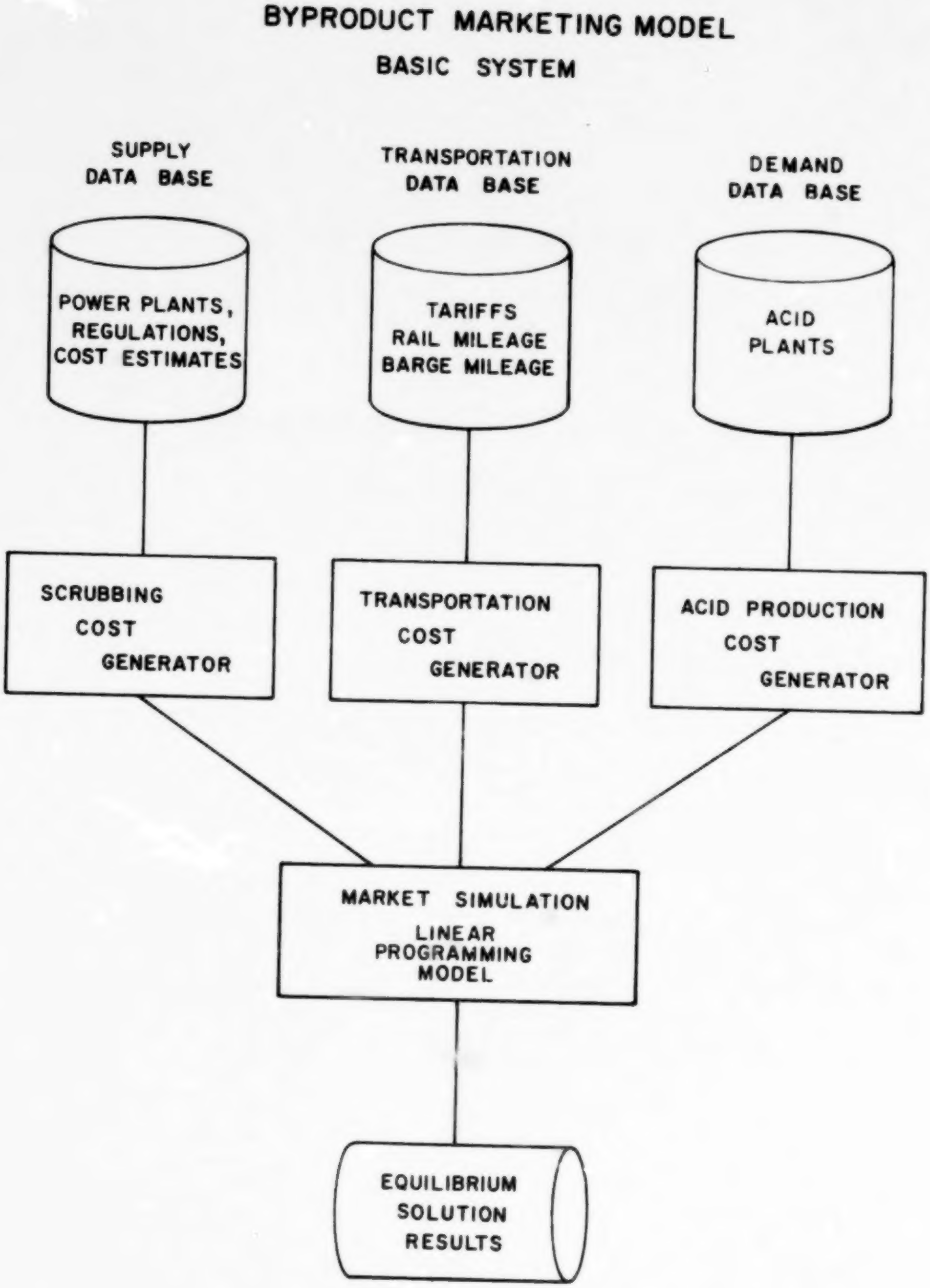
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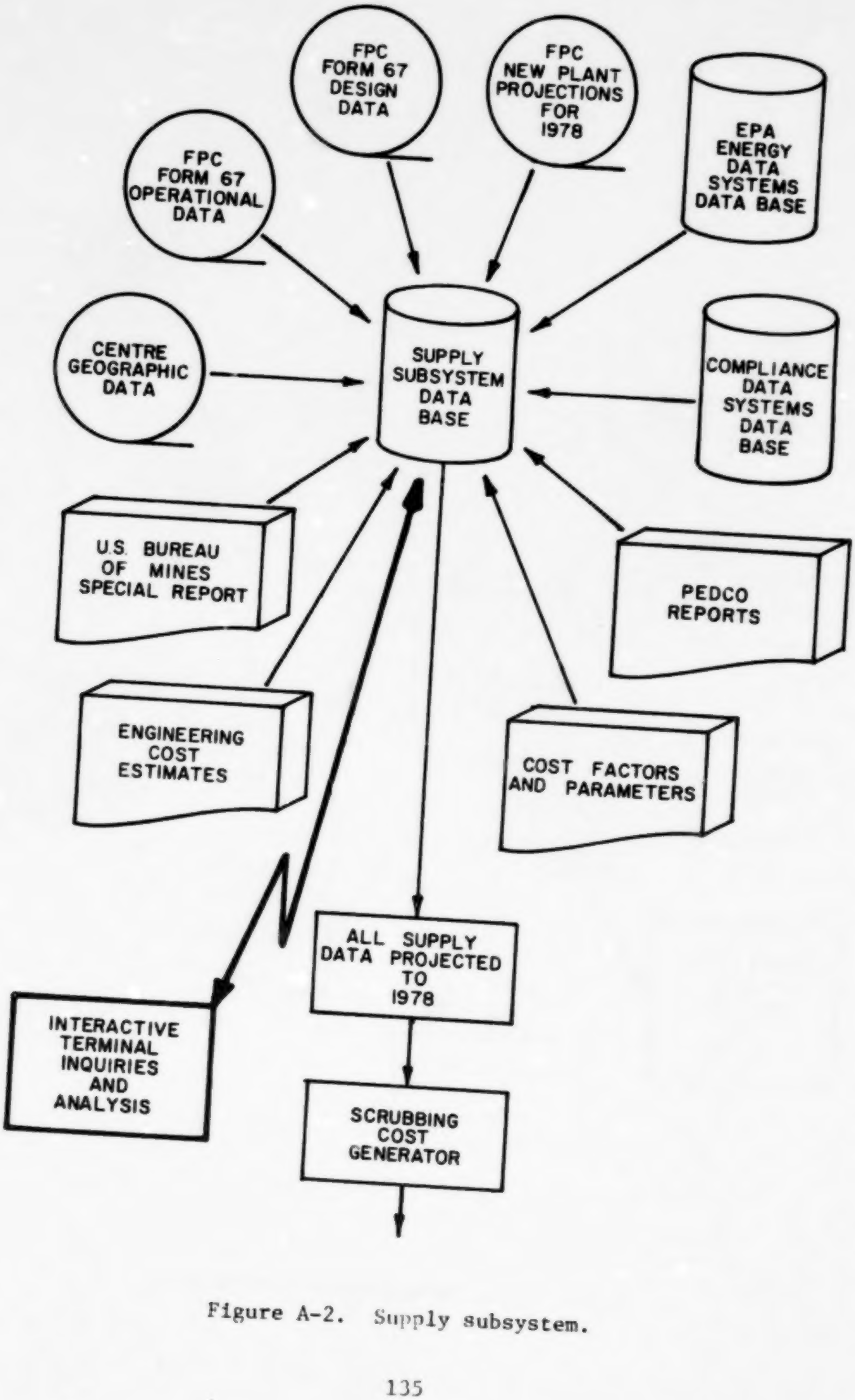
ACID PLANTS
SCRUBBING COST GENERATOR
TRANSPORTATION COST GENERATOR
ACID PRODUCTION COST GENERATOR
MARKET SIMULATION LINEAR PROGRAMMING MODEL
EQUILIBRIUM SOLUTION RESULTS

Figure A-1. Flow diagram for major system design requirements.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COMPLIANCE DATA SYSTEMS DATA BASE
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PEDCO REPORTS
ENGINEERING COST ESTIMATES
COST FACTORS AND PARAMETERS
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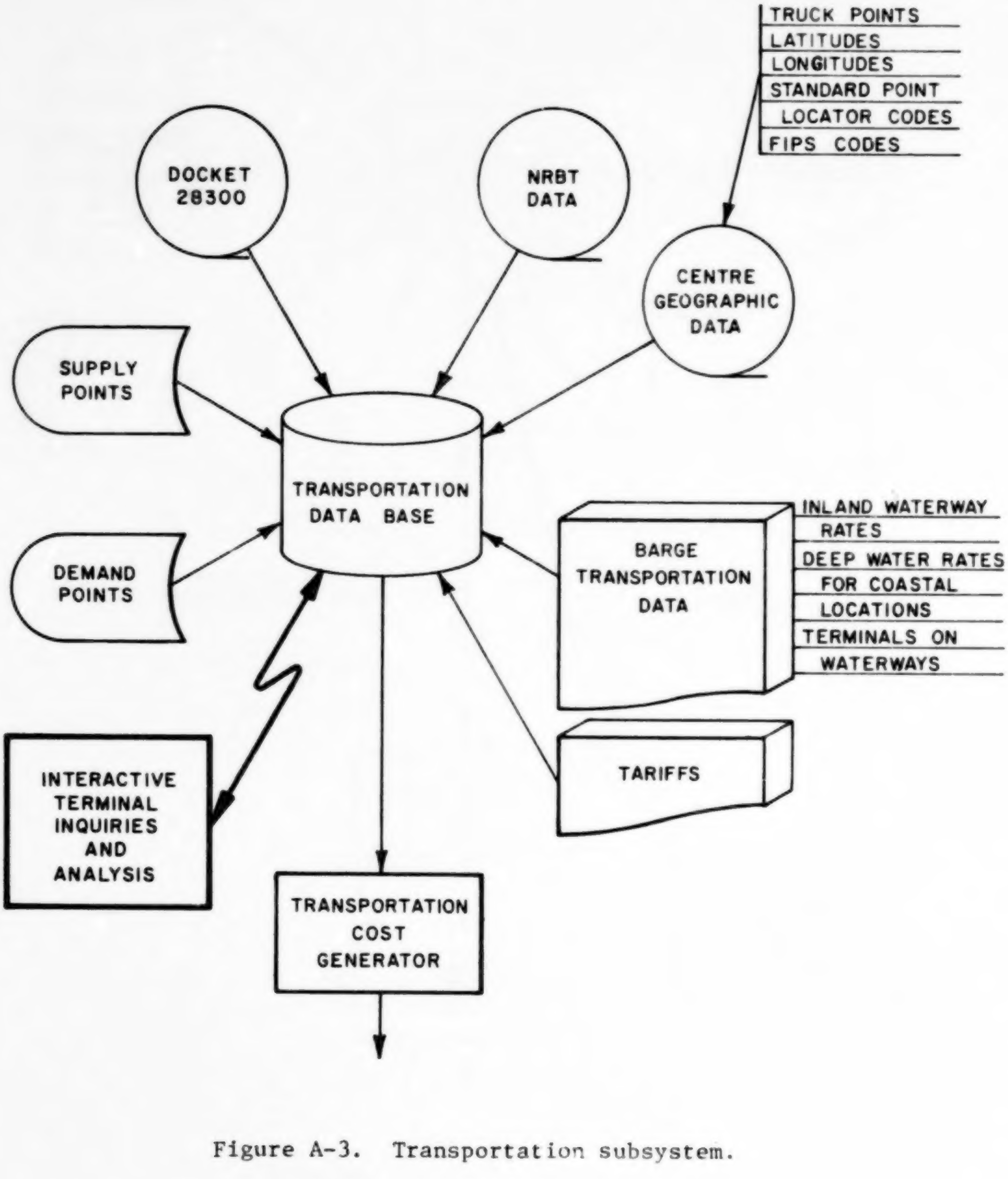
INTERACTIVE TERMINAL INQUIRIES AND ANALYSIS
SCRUBBING COST GENERATOR

Figure A-2. Supply subsystem.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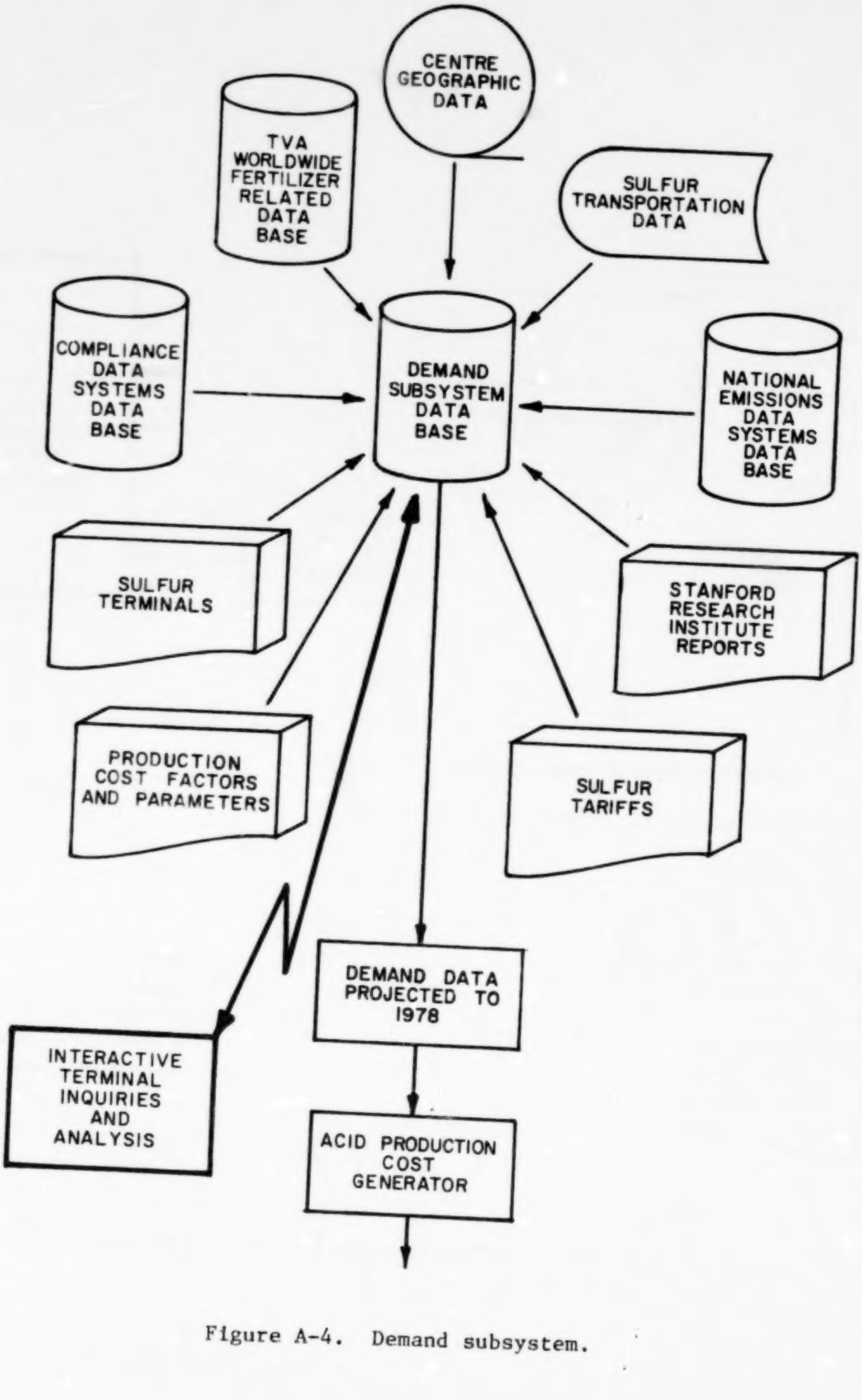
TRANSPORTATION DATA BASE
DEMAND POINTS
BARGE TRANSPORTATION DATA
INLAND WATERWAY RATES
DEEP WATER RATES FOR COASTAL LOCATIONS
TERMINALS ON WATERWAYS
TARIFFS
INTERACTIVE TERMINAL INQUIRIES AND ANALYSIS
TRANSPORTATION COST GENERATOR

Figure A-3. Transportation subsystem.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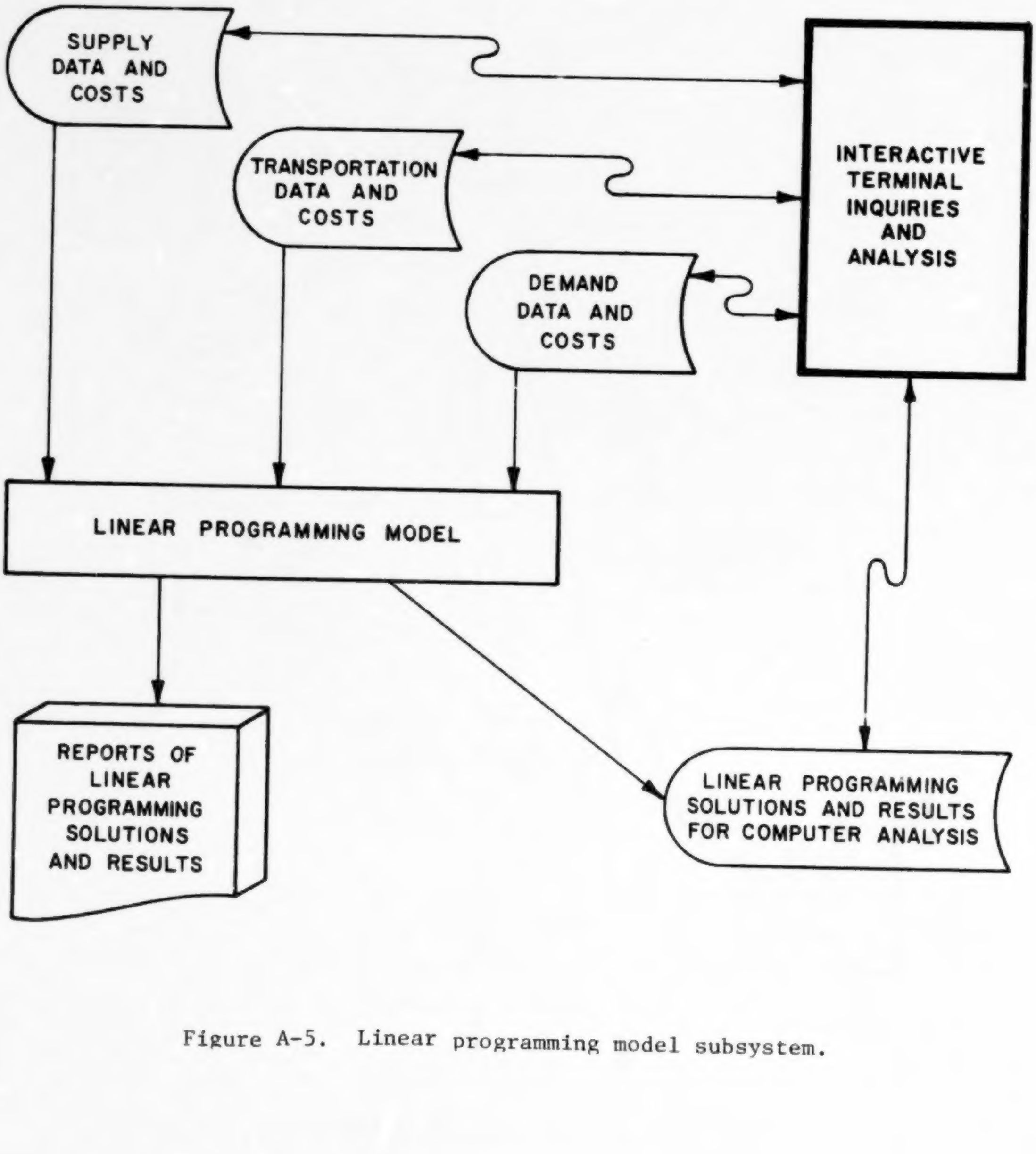
ACID PRODUCTION COST GENERATOR

Figure A-4. Demand subsystem.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LINEAR PROGRAMMING MODEL
REPORTS OF LINEAR PROGRAMMING SOLUTIONS AND RESULTS
LINEAR PROGRAMMING SOLUTIONS AND RESULTS FOR COMPUTER ANALYSIS

Figure A-5. Linear programming model subsystem.

APPENDIX B

A MATHEMATICAL STATEMENT OF MODEL

APPENDIX B

A MATHEMATICAL STATEMENT OF MODEL

CURRENT MATHEMATICAL MODEL

Demand Sector

$i = 1, 2, \ldots, n$ demand point numbers

C_i = Avoidable cost at demand point i per ton of byproduct

D_i = The quantity of byproduct which demand point i would purchase at price C_i or less

Utility Sector

$j = 1, 2, \ldots, m$ utility supply point numbers

CB_j = Average cost per ton of byproduct for producing at utility supply point j to meet SIP compliance

CL_j = Average cost in cents/MBtu of producing and disposing of limestone slurry at utility j to meet SIP compliance

CF_j = Average cost in cents/MBtu of using the best clean fuel alternative to bring utility j into compliance with SIP

BTU_j = The number of Btu input that would have to be scrubbed or cleaned to bring utility into compliance with SIP

s_j = Tons of byproduct produced per Btu input that would have to be scrubbed to bring utility j into compliance with SIP

CA_j = Average cost per ton of byproduct for the best alternative to byproduct production and marketing

$= s_j * \text{MIN}(CL_j, CF_j)$, if out of compliance

$= 0$, if within compliance

S_j = Tons of byproduct produced to bring utility j into compliance with SIP

$= s_j * BTU_j \quad (j = 1, 2, \ldots, m)$

Society

T_{ij} = Cost per ton of byproduct incurred by either the demand or supply sector in transferring a unit of byproduct from utility j to demand point i

X_{ij} = Tons of byproduct transferred from utility j to demand point i

X_{io} = Tons of byproduct used by demand point i from current source of supply

TSC = Total social cost or total cost of implementing the Clean Air Act to both the utility and demand sectors.

$$= \sum_{j=1}^{m} CA_j S_j + \underset{(X_{ij})}{\text{MIN}} \left\{ \left[\sum_{i=1}^{n} C_i X_{io} + \sum_{j=1}^{m} \sum_{i=1}^{n} (CB_j - CA_j + T_{ij}) X_{ij} \right] \right\}$$

subject to:

$$X_{io} + \sum_{j=1}^{m} X_{ij} = D_i \quad (i = 1, 2, \ldots, n)$$

$$\sum_{i=1}^{n} X_{ij} \leq S_j \quad (j = 1, 2, \ldots, m)$$

$$X_{ij} \geq 0 \quad \begin{array}{l} (i = 0, 1, 2, \ldots, n) \\ (j = 1, 2, \ldots, m) \end{array}$$

APPENDIX C

THE END-USE INPUT REQUIREMENTS FOR S AND H_2SO_4

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TABLE C-1. TONS OF ELEMENTAL S OR EQUIVALENT H_2SO_4 REQUIRED IN MANUFACTURE OF ONE TON OF INDICATED PRODUCT

Product	Short Tons of Sulfur or Equivalent Sulfur Per Ton of Product[a]	Equivalent Tons of H_2SO_4
Fertilizers		
Diammonium phosphate (DAP) 18-46-0 Grade	0.443[b]	1.355
Granular triple superphosphate (GTSP) 0-46-0 grade	0.311[b]	0.951
P_2O_5 in 54% P_2O_5 wet phosphoric acid	0.943[b]	2.885
Wet phosphoric acid (54% P_2O_5)	0.509[b]	1.557
Granulated ammonium polyphosphate (CAPP) 12-57-0	0.538[b]	1.646
Normal superphosphate (NSP) 0-20-0 grade	0.121[b]	0.370
Liquid fertilizer 11-37-0 grade	0.646[b]	1.976
Sulfuric acid, 100%	0.338[c]	1.000
Synthetic fiber intermediates		
Hydrogen cyanide (Modacrylic fiber)	0.081	0.248
Caprolactan (Nylon 6 fiber)	1.019[d]	3.117
Acetate rayon (fibers, photographic film, etc.)	0.034	0.104
Synthetic rubber (SBR)	0.005	0.015
Vulcanized synthetic rubber (SBR)	0.012	0.037
Carbon disulfide (fibers, cellophane, other chemicals)	0.936	2.863
Paper pulp	0.109	0.333
Indigo dye	0.297	0.909
Pheno-formaldehyde plastic moulding compound	0.0003	0.001
Phenol by sulfonation (plastics)	0.441	1.349
Explosives		
Nitrocellulose	0.169	0.517
Black powder	0.100	0.306
Nitroglycerine	0.014	0.043
Lithopone paint pigment	0.105	0.321
Leather tanning		
Vegetable tan	0.007	0.021
Chrome tan	0.076	0.232
Bordeau mixture (4-4-50) (fungicide)	0.002	0.006
Treflan (100%) (Herbicide)	0.420	1.285
Alum, 17% Al_2O_3 (water treatment chemical)	0.150	0.459
Sodium dichromate (tanning, dyeing, paint pigments,etc)	0.142	0.434
Uranium 235	18.090	55.341
Sodium sulfate (100%)	0.226[e]	0.691
Ammonium sulfate (100%)	0.243[f]	0.743

---

[a] All values are from Shreve, R.N. Chemical Process Industries 3rd Edition, McGraw-Hill Book Company, New York, 1967, unless otherwise noted.

[b] Unpublished TVA data.

[c] Average of several published values.

[d] Anon. Chemical Week, June 26, 1974, p. 41.

[e] Assuming direct neutralization of sulfuric acid with sodium hydroxide with no losses.

[f] Assuming direct neutralization of sulfuric acid with ammonium hydroxide with no losses.

APPENDIX D

FRASCH S PRODUCTION

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APPENDIX D

FRASCH S PRODUCTION

TECHNOLOGY

Wells which vary in depth from 200-2000 ft are sunk into a S dome using a method similar to that of sinking oil wells. The most economical way to get S out of the dome formation is to melt it and pump it out. This involves the use of superheated water at 330°F which is pumped into the dome.

The well consists of three concentric pipes and a casing. Inside the casing an 8-in. pipe is sunk through the cap rock over the dome to the bottom of the S deposit. Its lower end is perforated. A 4-in. pipe is lowered to within a short distance of the bottom. Last and innermost is a 1-in. pipe for compressed air reaching more than halfway to the bottom of the well. The superheated water is forced down the space between the 8- and 4-in. pipes and out into the S-bearing formation where it melts the S. The molten S collects at the bottom of the well where the pressure of the water forces it part of the way up the 4-in. pipe. The compressed air from the 1-in. pipe aerates and lightens the liquid S so that it will rise the rest of the way to the surface.

Once on the surface the hot, yellow S is pumped to a relay station for air removal and then either to heated tanks for storage in liquid form or to vats where it cools and solidifies. At this point, it is ready for marketing.

ECONOMICS

The primary information source for S mining economics is Jared E. Hazleton's *The Economics of the Sulfur Industry*, published by Resources for the Future, The John Hopkins Press, Baltimore and London, 1970. Investment costs given by Hazleton were updated to the third quarter of 1974 and mid-1978, as were the costs of labor, supervision, and utilities. The costs given exclude loading, royalties, and severance taxes. They also exclude all costs of exploration and development. They do include the drilling of new production wells since, on the average, one well will only produce for approximately 1 yr and will mine S from about 1/2 acre of a S dome.

The cost of mining Frasch S is very dependent upon the hot water rate associated with each mine, where the water rate is defined as the number of gallons required to produce 1 ton of S. The water rate varies drastically from mine to mine because of the widely divergent geological nature of S-containing salt domes (mines). Since the water is usually heated with natural gas, mining costs are very sensitive to the price of natural gas.

Within the framework of the third quarter 1974 estimates, the cost of natural gas was varied from $0.20-$3.00/kft^3 with an intermediate value of $1.00/kft^3. The $0.20/ft^3 rate is typical of existing contracts for old gas, the $1.00 rate is about that presently being paid under more recent contracts, and the $3.00 figure is a projected rate. For the mid-1978 estimates, the cost of natural gas was pegged at $2.50/kft^3.

DISCUSSION OF RESULTS

Using a constant water per ton of S rate of 1,600 gal, total heating water rates were varied for S production rates of 218,750, 875,000, and 1,750,000 long tons (LT)/yr. Costs were also estimated for a production rate of 350,000 LT/yr of S at a water rate of 4,000 gal of water per ton S, and a production rate of 155,400 LT/yr of S at a water rate of 9,000 gal of water per ton of S with a constant total heating water rate of 4 Mgal/day for both cases. It is felt that these ranges adequately represent the various Frasch S mining operations in the U.S. now and in the foreseeable future.

From the data in Table D-1, it can be seen that for mines with identical water rates (1600 gal/LT) the unit operating cost for the third quarter of 1974 for mining Frasch S decreases with increased mining rates and, of course, plant size. At a natural gas price of $1.00/kft^3, the unit cost decreases from $18.19/LT at a production rate of 218,750 LT/yr to $11.47/LT at a production rate of 1,750,000 LT/yr. Similar reductions are shown for mid-1978 costs. The marked sensitivity of operating costs to the price of natural gas is also shown in Table D-1.

The effect of plant heating water capacity and plant capacity upon total capital investment is shown in Table D-2, where the investment required per long ton per year decreases from $24.69 at a production rate of 218,750 LT/yr to $14.81 at a production rate of 1,750,000 LT/yr for third quarter 1974 costs.

In Table D-3 the effect of water rate and price of natural gas on cost of production for a mine having a capacity of 4 Mgal of water per day is given. These data show that as the water rate increases from 1600 to 9000 gal/LT at a natural gas cost of $1.00/kft^3, the operating cost for the third quarter of 1974 increases from $12.71 to $71.57/LT. Similar increases are shown for mid-1978 costs.

TABLE D-1. FRASCH S PRODUCTION - EFFECT OF NATURAL GAS COST ON PRODUCTION COST OF FRASCH S FOR VARIOUS PLANT HEATING WATER CAPACITIES

(Water rate: 1600 gal/LT S)

S production rate, LT/yr	Plant capacity, gal of water/day	Operating cost, $/LT of S
Third Quarter 1974 Costs		
	Natural Gas Cost: $0.20/kft^3	
218,750	1,000,000	13.68
875,000	4,000,000	8.25
1,750,000	8,000,000	7.05
	Natural Gas Cost: $1.00/kft^3	
218,750	1,000,000	18.19
875,000	4,000,000	12.71
1,750,000	8,000,000	11.47
	Natural Gas Cost: $3.00/kft^3	
218,750	1,000,000	29.45
875,000	4,000,000	23.86
1,750,000	8,000,000	22.51
Mid-1978 Costs		
	Natural Gas Cost: $2.50/kft^3	
218,750	1,000,000	30.04
875,000	4,000,000	23.07
1,750,000	8,000,000	21.42

TABLE D-2. FRASCH S PRODUCTION -
EFFECT OF PLANT HEATING WATER CAPACITY ON TOTAL CAPITAL INVESTMENT

(Water rate: 1600 gal/LT S)

S production rate, LT/yr	Plant capacity, gal of water/day	Total capital investment, $	Capital investment, $/LT/yr
Third Quarter 1974 Costs			
218,750	1,000,000	5,400,000	24.69
875,000	4,000,000	16,992,000	19.42
1,750,000	8,000,000	25,920,000	14.81
Mid-1978 Costs			
218,750	1,000,000	6,939,000	31.72
875,000	4,000,000	21,835,000	24.95
1,750,000	8,000,000	33,307,000	19.03

TABLE D-3. FRASCH S PRODUCTION - EFFECT OF NATURAL GAS COST ON OPERATING COST FOR VARIOUS WATER RATES

(Plant heating water capacity: 4 Mgal/day)

Water rate, gal/LT	S production rate, LT/yr	Operating cost, $/LT
Third Quarter 1974 Costs		
	Natural Gas Cost: $0.20/kft^3	
1,600	875,000	8.25
4,000	350,000	20.64
9,000	155,400	46.44
	Natural Gas Cost: $1.00/kft^3	
1,600	875,000	12.71
4,000	350,000	31.82
9,000	155,400	71.57
	Natural Gas Cost: $3.00/kft^3	
1,600	875,000	23.86
4,000	350,000	59.76
9,000	155,400	134.41
Mid-1976 Costs		
	Natural Gas Cost: $2.50/kft^3	
1,600	875,000	23.07
4,000	350,000	57.78
9,000	155,400	129.97

APPENDIX E

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APPENDIX E

S STORAGE TERMINAL OPERATION

TECHNOLOGY

The liquid S from the mines is pumped through insulated and steam-heated carbon steel pipe lines directly to terminals where it is stored either as a liquid in insulated and heated welded carbon steel tanks or to outdoor vats where it is cooled and solidified. Steam coils at pressures between 35 and 70 psig are used to maintain the molten S in the tanks at temperatures between 260 and 270°F (126-133°C). From the marketing terminal, the molten S is transported by barge, truck, or rail directly to the point of consumption in insulated vessels.

The solid S in the vats is broken out by modified bulldozers or power shovels. If it is to be reshipped as a solid, it is moved by conveyor belts to conventional road, rail, or water carriers. This method of reclaiming solid S generates considerable S dust which not only represents a monetary loss but has an adverse effect upon the environment. For this and other reasons such as contamination of the solid S during handling and shipping in dirty equipment, most S shipments are now made in the molten state. The dust problem may be minimized somewhat by processing the molten S into solid slates or prills for stockpiling and reclaiming. However, in the present study the cost of shipping solid S is based on reclamation from vats as described above.

ECONOMICS

The primary information source is World Sulfur Supply and Demand, 1960-1980 published in New York by the United Nations Industrial Development Organization, Vienna. Much valuable information was also obtained from "Technical and Economic Evaluation of Fertilizer Intermediates for use by Developing Countries" prepared for the Agency for International Development by TVA (TVA Bulletin Y-3).

Investment costs given in the above publications were updated to the third quarter of 1974 and mid-1978 as were the costs of labor, supervision, and utilities. In all cases the annual throughput was taken as four times the primary storage capacity. Costs were estimated for primary storage capacities of 20,000, 40,000, and 60,000 LT, giving annual throughputs of 80,000, 160,000, and 240,000 LT respectively. Costs were estimated for terminals receiving solid S and redelivering 60% of the S as a liquid and terminals receiving all S in the liquid form and redelivering as the liquid. Solid S storage capital costs include site preparation, foundations, and cost of handling facilities such as conveyors. Liquid S storage costs include tanks (excluding piling), all onsite lines, valves, meters, etc., but not delivery or discharge lines beyond battery limits. Tank capacities and hence costs are based on standard units 40 ft high with varying diameters.

Except for the terminal with a throughput of 240,000 LT/yr (60% of the S delivered as a liquid), one melter of the appropriate size was considered the most economical. In the 240,000 LT/yr terminal, two melters were assumed. All terminals receiving solid S were assumed to reship 60% of the throughput as liquid.

For those terminals receiving and delivering molten S only, the terminal with the annual throughput of 80,000 LT/yr was assumed to have two storage tanks holding 10,000 LT each; the terminal with the throughput of 160,000 LT was assumed to have two tanks holding 20,000 LT each; the terminal with a throughput of 240,000 LT was assumed to have two tanks holding 30,000 LT each.

DISCUSSION OF RESULTS

As shown in Table E-1, increasing the size of the terminals decreases the unit storage costs. For those terminals which receive solid S and redeliver 60% of the S in the molten form, the estimated costs as of the third quarter of 1974 are $4.67/LT for a terminal with an annual throughput of 80,000 LT, $3.71/LT for a throughput of 160,000 LT, and $3.26/LT for a throughput of 240,000 LT. Capital costs in dollars per long ton per year are $9.00, $7.20, and $6.87 respectively.

The terminals which handle only molten S have even lower costs, resulting primarily from the elimination of the labor- and maintenance-intensive solid S handling operation. For these terminals the estimated costs, as of the third quarter of 1974, are $4.14/LT for an annual throughput of 80,000 LT; $2.85/LT for a throughput of 160,000 LT, and $2.47/LT for a throughput of 240,000 LT.

Greater throughput rates, up to eight times the primary storage capacity, are possible in S terminal operations. These greater throughput rates would significantly decrease unit operating and capital costs.

TABLE E-1. S STORAGE TERMINAL OPERATION - EFFECT OF THROUGHPUT CAPABILITIES ON TOTAL CAPITAL INVESTMENT AND OPERATING COSTS

Throughtput, LT/yr	Total capital investment, $	Capital investment, $/LT/yr	Operating cost, $/LT of S
Third Quarter 1974 Costs			
Terminals Receiving Solid S and Redelivering 60% Liquid			
80,000	720,000	9.00	4.67
160,000	1,151,700	7.20	3.71
240,000	1,648,390	6.87	3.26
Terminals Receiving and Redelvering All Liquid			
80,000	647,840	810	4.14
160,000	820,600	513	2.85
240,000	928,568	387	2.47
Mid-1978 Costs			
Terminals Receiving Solid S and Rdelivering 60% Liquid			
80,000	925,200	1157	6.36
160,000	1,479,900	925	5.11
240,000	2,118,200	883	4.16
Terminals Receiving and Redelivring All Liquid			
80,000	832,500	1041	5.90
160,000	1,054,500	659	4.26
240,000	1,193,200	497	3.78

APPENDIX F

PRODUCTION, STORAGE, AND RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING ELEMENTAL S

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APPENDIX F

PRODUCTION, STORAGE, AND RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING ELEMENTAL S

H_2SO_4 PRODUCTION FROM ELEMENTAL S

Technology

Basically H_2SO_4 is produced by burning S or S-bearing materials to form SO_2. The SO_2 is oxidized by air in the presence of a catalyst to form sulfur trioxide (SO_3) which combines with water vapor to form H_2SO_4.

The various sources of SO_2 for manufacture of H_2SO_4 include (1) elemental S, (2) pyrites [sulfide ores of iron (Fe), Cu, Pb, or Zn], (3) H_2S from sour gas or petroleum, (4) S-bearing ores of volcanic origin, (5) waste gases from metallurgical refining operations, and (6) waste gases from combustion of S-containing fuels. This study is concerned only with the production of acid from elemental S. In addition to the SO_2 source alternatives listed above, there are also alternate methods of conversion of SO_2 to SO_3.

There are two principal processes for conversion of SO_2 to the trioxide form: the chamber and the contact processes. The older chamber process which was introduced in the 18th century uses nitrogen oxides (NO_x) as the oxygen-carrying catalyst for the conversion of SO_2 to SO_3. The reactions which produce the SO_3 and H_2SO_4 take place either in huge lead chambers or packed towers.

The modern contact process facilitates conversion of SO_2 to SO_3 by use of a metal or metal-oxide catalyst. The SO_3 is then passed through an absorption tower where it is absorbed in recirculating concentrated acid. The major advantages of the contact process are that concentrated acid of high purity can be produced directly and compact plants of high capacity are feasible. Plants of 1000 ton/day capacity are now rather commonplace and plants having capacities of 2000 tons/day and above have recently been constructed. Very few of the old chamber process plants are still in operation in the U.S. and the vast majority of plants use the more efficient contact process. For this reason, the present study is confined to H_2SO_4 produced by the contact process.

Contact H_2SO_4 plants built prior to 1960 average 95.5% conversion of elemental S to H_2SO_4. Plants built after 1960 are more efficient with 97% conversion. However, neither of these classes of plant can meet present emission standards which require a conversion efficiency of 99.7%.

Those existing contact plants which fail to meet emission standards are of the single contact-single absorption type; i.e., the gas stream containing the SO_2 from the S burner is passed through a converter where, in contact with the catalyst, the SO_2 is oxidized to SO_3 and the oxidized gases are passed through an absorber where most of the SO_3 is removed to form acid. However, the tail gas leaving the absorber contains too much unconverted SO_2 to meet emission standards. One method of solving this problem is to pass the gases from the absorber through a second converter and a second absorber. This second conversion and absorption results in an overall conversion efficiency of 99.7% or greater, thus meeting emission standards. Existing single contact-single absorption plants can be retrofitted with an additional converter-absorber system to enable them to meet emission standards. Other systems are also available for this purpose and will be discussed in another section of this report. Virtually all new H_2SO_4 plants are built with two converter-absorber systems in series in order to meet emission standards; these are called dual contact-dual absorption plants. Cost data for both types of plants have been developed.

Economics

Monsanto Enviro-Chem Systems, Inc., The Ralph M. Parsons Company, and Davy Powergas, Inc., were the primary sources of capital cost data and utility and labor requirements for both the single contact-single absorption and the dual contact-dual absorption plants. Other valuable information was obtained from Chemical Process Industries by R. Norris Shreve, McGraw-Hill Book Company; The Economics of Sulfuric Acid Production prepared for the Agency for International Development by TVA (TVA Bulletin Y-28); The Fertilizer Manual published by the United Nations Industrial Development Organization, New York; and The Manufacture of Sulfuric Acid edited by Werner W. Duecker and James R. West, Reinhold Publishing Corporation, New York.

Investment costs from the above sources were calculated for the third quarter of 1974 and mid-1978, as were the costs of labor, supervision, and utilities. The cost of S was excluded from the estimates because of its variability. Credit for byproduct steam was included. Investment costs include capital costs for 30 days' storage of acid and S for each plant size investigated.

Costs for single contact-single absorption plants having capacities of 50, 100, 250, 750, and 1500 tons/day of 100% H_2SO_4 were estimated as well as costs for dual contact-dual absorption plants having capacities of 100, 250, 750, and 1500 tons/day. Costs for dual contact-dual absorption plants of 50 ton/day capacity were not estimated as it is doubtful if plants of such small capacity will ever be built. All plants were assumed to operate 330 days/yr.

Discussion of Results

As with most chemical plants there is a decided unit cost advantage with increasing capacity. Although this cost advantage is substantial at all levels of capacity explored, it decreases with increasing size of the acid plant as shown in Table F-1.

TABLE F-1. H_2SO_4 PRODUCTION FROM ELEMENTAL S - EFFECT OF ACID PLANT CAPACITY ON TOTAL CAPITAL INVESTMENT AND OPERATING COSTS FOR SINGLE CONTACT-SINGLE ABSORPTION (SC-SA) AND DUAL CONTACT-DUAL ABSORPTION (DC-DA) H_2SO_4 PLANTS

Acid plant capacity, tons of 100% H_2SO_4/day	Total capital investment, $		Capital investment, $/ton of 100% H_2SO_4/yr		Operating cost, $/ton[a] of 100% H_2SO_4	
	SC-SA	DC-DA	SC-SA	DC-DA	SC-SA	DC-DA
Third Quarter 1974 Costs						
50	2,737,000	-	165.88	-	41.06	-
100	3,220,000	3,942,000	97.58	119.45	23.13	26.35
250	4,913,800	6,443,000	59.56	78.10	12.92	15.44
750	9,494,500	11,211,000	38.36	45.30	7.10	7.33
1,500	14,600,800	18,068,000	29.50	36.54	4.85	5.00
Mid-1978 Costs						
50	3,517,000	-	213.15	-	51.96	-
100	4,138,000	5,065,000	125.39	153.48	29.11	33.26
250	6,314,000	8,279,000	76.53	100.35	16.10	19.16
750	12,200,000	14,406,000	49.29	58.21	8.68	8.76
1,500	18,762,000	23,243,000	37.90	46.96	5.80	5.76

a. Does not include the cost of S.

For example, for single contact-single absorption plants built in the third quarter of 1974, the capital investment required in terms of dollars per ton of 100% H_2SO_4/yr is $165.88 for a 50 ton/day plant and $29.50 for a 1500 ton/day plant, while the unit capital investment for a 750 ton/day plant is $38.36, only $8.86/ton of acid per day greater than that for the 1500 ton/day plant. First year operating costs (excluding S) for single contact-single absorption plants built in the third quarter of 1974 are $41.06/ton of 100% H_2SO_4 for a 50 ton/day plant and $4.85/ton for a 1500 ton/day plant, while the operating cost for a 750 ton/day plant is $7.10/ton, a difference of only $2.25/ton greater than that for the 1500 ton/day plant. These trends can also be seen in the data for dual contact-dual absorption plants.

The data given above also show that dual contact-dual absorption plants are more costly to build and generally more costly to operate even though they have a somewhat higher S recovery efficiency than single contact-single absorption plants (an exception will be discussed below). For example, the capital investment required in terms of dollars per ton of 100% H_2SO_4/yr for 100 ton/day plants built in the third quarter of 1974 is $97.58 for a single contact-single absorption plant and $119.45 for a dual contact-dual absorption plant. First year operating costs (excluding S) for a 100 ton/day plant built in the third quarter of 1974 are $23.13/ton of 100% H_2SO_4 for a single contact-single absorption plant and $26.35/ton for a dual contact-dual absorption plant, while the operating costs for 1500 ton/day plants are $4.85/ton for a single contact-single absorption plant and $5.00/ton for a dual contact-dual absorption plant.

The major factor contributing to the decreasing difference in operating costs between single contact-single absorption and dual contact-dual absorption plants with increasing size is the greater thermal efficiency of the larger dual contact-dual absorption plants. The higher thermal efficiency of these plants results in the production of more byproduct steam for which an operating cost credit can be taken. This proportionately larger byproduct steam generation credit, coupled with the relatively higher credit value for this commodity in mid-1978 as contrasted with the projected values of the other utilities, actually results in a slightly lower operating cost for a 1500 ton/day dual contact-dual absorption plant than the same sized single contact-single absorption plant in mid-1978, i.e., $5.76/ton for the dual contact-dual absorption plant versus $5.80/ton for the single contact-single absorption plant. The operating costs before steam credits are taken are $8.52/ton and $7.90/ton respectively. However, since single contact-single absorption plants will not be built in mid-1978 unless emission standards for H_2SO_4 plants are greatly relaxed, this comparison between the two types of plants is of academic interest only.

H_2SO_4 STORAGE TERMINAL OPERATION

Technology

Concentrated (93-98%) H_2SO_4 is usually stored in carbon steel vessels with an expected life of about 25 yr. Carbon steel is suitable because a protective sulfate film formed on the steel surfaces inhibits corrosion. However, this film can be eroded where flow velocities are excessive. Hence, tank nozzles, pipe lines, valves, and pumps must be properly sized if carbon steel is used. If flow velocities are excessive, stainless steel is recommended for pipe lines, etc. Plastic-lined material may also be used. Plastic pipe by itself is not recommended as it may be easily broken by a falling object or some other shock.

H_2SO_4 tanks are usually designed for no additional pressure above the weight of the acid. Steel plates 3/8 in. thick are usually used in tank construction, with the joints welded both inside and out.

All storage tanks are above ground on concrete piers or saddles so spaced and of such a height that leaks may be detected by visual inspection of the bottom sections of the tanks. Each tank is equipped with a vent to allow air to move in and out of the tank as the acid level changes, or as breathing takes place because of temperature changes. The vent or breather is equipped with a drying agent such as silica gel, which is inert to acid fumes, in order to prevent dilution of the acid (dilute acids are more corrosive) with the moisture in the air and to prevent interface corrosion of the tank wall.

H_2SO_4 exhibits an unusual freezing point curve. The freezing point of 93% H_2SO_4 is minus 30°F and the freezing point of 98% H_2SO_4 is 35°F. Therefore, suitable precautions must be taken when storing acids of different strengths at various temperatures.

Economics

The concept of shipping H_2SO_4 from the point of manufacture to a storage terminal for transshipment to the consumer instead of direct shipment from the producer to the consumer is relatively new. Hence, not much data exists on costs of operating such a terminal. Data in the study Detailed Cost Estimates for Advanced Effluent Desulfurization Processes by G. G. McGlamery, et al. (EPA-600/2-75-006 or PB-242 541/1WP, January 1975) was used to estimate operating costs for H_2SO_4 terminals. These costs were based on the use of carbon steel storage tanks on concrete piers surrounded by an earthen dike, carbon steel acid pumps, valves and piping, and a railroad car loading dock.

Costs were estimated for three sizes of terminals having primary storage capacities of 4,680, 11,376, and 21,960 tons of 100% H_2SO_4 and yearly throughput rates of 45,300, 110,400, and 213,500 tons of 100% H_2SO_4 respectively. These annual throughput rates are about 10 times the primary storage capacity. Costs were estimated for the third quarter of 1974 and mid-1978.

Discussion of Results

The data in Table F-2 show that the economies of scale prevail--the larger the storage capacity the lower the unit investment and operating costs. For example, a terminal with a throughput of 45,200 tons/yr of 100% H_2SO_4 has a unit investment cost in the third quarter of 1974 of \$5.97/ton of 100% H_2SO_4/yr and a total operating cost of \$1.68/ton of 100% H_2SO_4. The corresponding figures for a terminal with a throughput of 213,500 tons of 100% H_2SO_4/yr are \$3.37 and \$0.77 respectively. The mid-1978 costs show the same trend.

TABLE F-2. H_2SO_4 STORAGE TERMINAL OPERATION - EFFECT OF THROUGHPUT CAPABILITIES ON TOTAL CAPITAL INVESTMENT AND OPERATING COSTS

Throughtput, tons 100% H_2SO_4/yr	Total capital investment, \$	Capital investment, \$/ton 100% H_2SO_4/yr	Operating cost, \$/ton 100% H_2SO_4
Third Quarter 1974 Costs			
45,200	270,000	5.97	1.68
110,400	475,000	4.30	1.05
213,500	720,000	3.37	0.77
Mid-1978 Costs			
45,200	347,000	7.68	2.18
110,400	610,000	5.53	1.38
213,500	925,200	4.33	1.02

RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING ELEMENTAL S

Technology

As mentioned in the preceding section, most existing H_2SO_4 plants are contact plants of the single contact-single absorption type which have 95-97% S conversion efficiencies. Since a minimum of 99.7% S conversion efficiency is required to meet present emission standards for new and modified plants, these existing single contact-single absorption plants must be retrofitted with some system which will enable them to meet these standards. There are four major methods for doing this.

1. Adding another converter-absorber system (dual contact-dual absorption)

2. Scrubbing the stack gas with a sodium sulfite-bisulfite solution (Wellman-Lord process)

3. Scrubbing the stack gas with an ammonium sulfite-bisulfite solution (NH_3 absorption process)

4. Adsorbing the contaminants in the stack gas on molecular sieves (Purasiv S process)

In the dual contact-dual absorption system, the tail gas from the absorber of the existing acid plant is passed through a booster blower to provide the pressure necessary to force the gas through the remaining additional equipment. The tail gas must then be heated before passing through the additional converter where most of the unreacted SO_2 in the tail gas is converted to SO_3. Heating of the gas can be done either by bleeding in a portion of the hot gases from the S furnace or employing a separate fuel-fired heater. The fuel-fired heater is generally used for retrofit because of smaller capital costs and less downtime for tie-in of the abatement system to the acid plant. An air heater is included in the fuel-firing system to minimize fuel consumption. The gas from the converter is passed through an additional absorber where the SO_3 is removed to form more acid. The tail gases from this second absorber, after passing through a mist eliminator, can be vented to the atmosphere without exceeding emission limitations. A mist eliminator is also added to the absorber of the existing plant to protect the booster blower and heat exchangers from corrosion by acid carry-over from the absorber.

In the Wellman-Lord process the tail gas from the acid plant is scrubbed in an absorber with a regenerable sodium sulfite-bisulfite solution. The resulting solution is thermally regenerated in an evaporator-crystallizer and the SO_2 driven off is returned to the drying tower in the acid plant. The slurry from the regenerator is redissolved in water from the condenser on the evaporator-crystallizer and returned to the absorber. The small portion of the sodium sulfite which is oxidized to sulfate is removed in a purge stream along with a small amount of sodium thiosulfate which forms in the process.

The NH_3 absorption process consists of scrubbing the SO_2 in the tail gases from the existing acid plant in a solution of ammonium sulfite-bisulfite and discharging the scrubbed gases to the atmosphere through a high-efficiency particulate collector (such as a Brink mist eliminator) in order to remove the extremely fine particles of ammonium sulfite-bisulfite from the gas stream. The scrubbing solution from the absorber-scrubber is acidified with H_2SO_4 and the resulting ammonium sulfate [$(NH_4)_2SO_4$] solution is air stripped to remove SO_2 which is returned to the drying tower of the H_2SO_4 plant. The resulting $(NH_4)_2SO_4$ solution can be used in a diammonium phosphate process or processed in a separate crystallization operation.

The Purasiv S process uses beds of molecular sieves to remove the SO_2 from the tail gas of the existing acid plant. The tail gas is passed through one of two parallel beds of molecular sieves. While one adsorbent bed is treating the gases, the other is being regenerated with hot air. The regenerated SO_2-air stream is returned to the drying tower of the acid plant where it substitutes for the dilution air usually drawn into the tower. Bed switching is accomplished without any interruption in flow or removal of SO_2 from the tail gas stream. The cleaned gas is vented to the atmosphere.

Economics

Capital and operating costs for the dual contact-dual absorption system were obtained from The Ralph M. Parsons Company, Monsanto Enviro-Chem, Inc., and Davy Powergas, Inc. Costs from these sources were essentially the same and were averaged for use in the estimates. The capital costs include all of the equipment mentioned in the section on technology plus the necessary valves, piping, foundations, engineering costs, contractor fees, etc.

The Wellman-Lord process is proprietary and the source of information concerning the process was Davy Powergas. Neither credit for possible sales of the sodium sulfate byproduct nor disposal costs if the product is not marketable is included in the cost estimates.

The source of information concerning the NH_3 absorption process was also Davy Powergas. In the cost estimates, no credit was taken for the byproduct $(NH_4)_2SO_4$. The estimates include costs of the absorber, stripper, mist eliminator, pumps, piping, foundation, engineering costs, etc., but do not include any equipment for crystallization of the $(NH_4)_2SO_4$.

The Purasiv S process which uses beds of molecular sieves to remove the SO_2 from the acid plant tail gas is the property of the Union Carbide Corporation and all cost information was obtained from them. The estimates include the cost of the parallel bed system, the furnace for heating the regeneration air, fans, ducts, foundations, engineering costs, etc., as well as an expansion of an existing substation, a cooling water tower, and fuel oil storage. Because of the specialized nature of the adsorbent, a service contract for its renewal is included in the estimate rather than outright purchase of new adsorbent and reprocessing of spent material.

Since all four methods of abating the emissions from H_2SO_4 plant stack gases result in an increased recovery of S, a credit is given in the cost estimates for the equivalent S recovered.

Cost estimates were prepared for each of the four methods for controlling emissions from existing single contact-single absorption H_2SO_4 plants having capacities of 50, 100, 250, 750, and 1500 tons of 100% H_2SO_4/day and operating 330 days/yr. Costs were calculated for the third quarter of 1974 and for mid-1978.

Discussion of Results

The data in Table F-3 show that of the four retrofit systems evaluated, the NH_3 absorption scheme is the least capital intensive, varying from $21.70/ton of 100% H_2SO_4/yr for a 50 ton/day plant to $3.96 for a 1500 ton/day plant for the third quarter of 1974. The Wellman-Lord system is somewhat more capital intensive with corresponding costs of $27.12 and $4.81. The two most capital intensive systems are the dual contact-dual absorption system with costs of $33.61/ton of 100% H_2SO_4/yr for a 50 ton/day plant and $6.91 for a 1500 ton/day plant, and the molecular sieve scheme, with values of $44.06 and $7.27 respectively. The mid-1978 costs exhibit the same trend.

However, the data in Table F-4 show that there is considerable variation in overall operating costs, depending upon plant size and the retrofit system used. The lowest average cost for the third quarter of 1974 for all plant sizes evaluated is that for the dual absorption system, $4.36/ton of 100% H_2SO_4, followed by the molecular sieves at $4.96, the NH_3 absorption system at $5.05, and the Wellman-Lord scheme at $5.78. The same trend is exhibited by the data for mid-1978.

The situation changes when comparisons are made on individual plant sizes. The third quarter of 1974 data indicate that the dual absorption and molecular sieves schemes are cheaper to operate for 50 and 100 ton/day plants, with costs of $7.49 and $5.17/ton of 100% H_2SO_4, respectively, for the dual absorption system and $9.16 and $6.12 for the molecular sieve scheme; the corresponding figures for the NH_3 absorption scheme are $10.55 and $6.35, while for the Wellman-Lord system they are $11.79 and $7.22. For the 250 ton/day plants, the dual absorption and NH_3 absorption systems are the least expensive to operate with almost identical third quarter 1974 costs of $3.87 and $3.89/ton of 100% H_2SO_4 respectively; the corresponding costs for the molecular sieves and Wellman-Lord systems are $4.43 and $4.55. The cheapest operating costs for the 750 and 1500 ton/day plants are associated with the NH_3 absorption system, with costs of $2.50 and $1.98 respectively. The operating costs for the other systems for the 750 ton/day plants are almost identical, varying from $2.96 to $2.99/ton of 100% H_2SO_4; for the 1500 ton/day plants the operating costs of the other systems vary from $2.14 for the molecular sieves scheme to $2.36 for the Wellman-Lord system.

The mid-1978 operating costs also vary widely between plant sizes and abatement systems, with roughly the same trends as the third quarter 1974 costs.

TABLE F-3. RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING ELEMENTAL S - EFFECT OF ACID PLANT CAPACITY ON THE TOTAL CAPITAL INVESTMENT FOR EMISSION CONTROL SYSTEMS

Acid plant capacity, tons of 100% H_2SO_4/day	Retrofit system							
	Dual contact-dual absorption		Wellman-Lord		Ammonia absorption		Molecular sieves	
	Total capital investment, $	Investment, $/ton 100% H_2SO_4/yr	Total capital investment, $	Investment, $/ton 100% H_2SO_4/yr	Total capital investment, $	Investment, $/ton 100% H_2SO_4/yr	Total capital investment, $	Investment, $/ton 100% H_2SO_4/yr
Third Quarter 1974 Costs								
50	554,500	33.61	447,400	27.12	358,000	21.70	727,000	44.06
100	691,000	20.94	557,400	16.89	445,900	13.51	906,000	27.45
250	1,144,000	13.87	923,000	11.19	738,400	8.95	1,500,000	18.18
750	2,538,000	10.25	1,750,000	7.07	1,400,000	5.66	2,750,000	11.11
1,500	3,418,000	6.91	2,380,000	4.81	1,960,000	3.96	3,600,000	7.27
Mid-1978 Costs								
50	712,500	43.18	574,900	34.84	460,000	27.88	934,200	56.62
100	887,900	26.91	716,300	21.71	573,000	17.36	1,164,200	35.28
250	1,470,000	17.82	1,186,100	14.38	949,000	11.50	1,927,500	23.36
750	3,261,300	13.18	2,248,800	9.09	1,799,000	7.27	3,533,800	14.28
1,500	4,392,100	8.87	3,058,300	6.18	2,518,600	5.09	4,626,000	9.35

TABLE F-4. RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING ELEMENTAL S - EFFECT OF ACID PLANT CAPACITY ON THE OPERATING COSTS OF EMISSION CONTROL SYSTEMS

Acid plant capacity, tons of 100% H_2SO_4/day	Operating cost, \$/ton 100% H_2SO_4			
	Dual absorption	Wellman-Lord	NH_3 absorption	Molecular sieves
Third Quarter 1974 Costs				
50	7.49	11.79	10.55	9.16
100	5.17	7.22	6.35	6.12
250	3.87	4.55	3.89	4.43
750	2.96	2.99	2.50	2.97
1,500	2.30	2.36	1.98	2.14
Average	4.36	5.78	5.05	4.96
Mid-1978 Costs				
50	10.40	15.50	14.11	12.54
100	7.41	9.72	8.81	8.62
250	5.74	6.36	5.71	6.43
750	4.53	4.38	3.95	4.59
1,500	3.68	3.58	3.28	3.44
Average	6.35	7.91	7.17	7.12

In actual application the NH_3 scrubbing system would probably have a distinct advantage over the others if the byproduct $(NH_4)_2SO_4$ could be utilized, such as would be the case for a captive acid plant located in a fertilizer complex. If no credit can be taken for the $(NH_4)_2SO_4$, then the decision as to which system to use becomes largely dependent upon individual acid plant factors such as location, space available for retrofit, etc.

APPENDIX G

DEMAND SCHEDULE FOR H_2SO_4 PLANTS

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TABLE G-1. DEMAND SCHEDULE FOR H_2SO_4- EASTERN ACID PLANTS

Annual capacity, ktons	Avoidable cost of production, $	Plant name	Location	
6.00	90.47	Eastman Kodak	Rochester	NY
17.00	66.35	Home Guano Company	Dothan	AL
52.00	57.91	Detroit Chemical Co.	Detroit	MI
67.00	56.44	Kerr-McGee	Cottondale	FL
87.00	51.70	Royster Company	Norfolk	VA
152.00	50.35	Minn Min and Smelt	Copley	OH
176.00	49.51	Columbia Nitrogen	Moultrie	GA
201.00	46.96	American Cyanamid	Kalamazoo	MI
266.00	46.19	American Cyanamid	Bound Brook	NJ
306.00	45.66	Swift Chem Company	Calumet City	IL
436.00	45.58	Allied Chemical Corp	Cleveland	OH
468.00	45.25	Swift Chem Co.	Wilmington	NC
524.00	44.82	Marion Manufacturing	Indianapolis	IN
564.00	44.70	Borden Chemical	Streator	IL
599.00	44.55	Weaver Fertilizer	Norfolk	VA
634.00	44.28	Swift Chem Co.	Norfolk	VA
739.00	44.27	Olin Corporation	N. Little Rock	AR
789.00	44.08	American Cyanamid	Joliet	IL
989.00	43.25	E. I. Dupont De Nem	Cleveland	OH
1,031.00	42.51	W. R. Grace and Co.	Charleston	SC
1,206.00	42.41	E. I. Dupont De Nem	North Bend	OH
1,232.00	41.19	American Cyanamid	Mobile	AL
1,342.00	40.50	E. I. Dupont De Nem	Gibbstown	NJ
1,452.00	40.44	Pennsalt Chemicals	Tulsa	OK
1,502.00	40.31	American Cyanamid	Fortier	LA
1,607.00	40.29	U.S. Industrial Chem	Desoto	KS
1,705.00	39.68	W. R. Grace and Co.	Joplin	MO
1,780.00	39.36	Delta Chemical	Searsport	ME
1,835.00	39.15	Reichhold Chemicals	Tuscaloosa	AL
1,910.00	38.91	E. I. Dupont De Nem	Cornwells Hts.	PA
1,980.00	38.72	USS Agri-Chem	Navassa	NC
2,015.00	38.62	Cities Service Oil	Monmouth Jct	NJ
2,147.00	38.42	Army Ammunition Plt	Tyner	TN
2,233.00	38.12	El Paso Products	El Paso	TX
2,313.00	38.06	Borden Chemical	Norfolk	VA
2,411.00	38.05	U.S. Industrial Chem	Dubuque	IA
2,546.00	38.03	Allied Chemical Corp	Nitro	WV
2,666.00	37.68	Stauffer Chemical Co.	Ft. Worth	TX
2,756.00	37.27	E. I. Dupont De Nem	Richmond	VA
2,856.00	36.84	Occidental Ag Chem	Plainview	TX
2,951.00	36.76	American Cyanamid	Hamilton	OH
2,999.00	36.22	Acme (Wright) Fert Co.	Acme	NC

(continued)

TABLE G-1 (continued)

Annual capacity, ktons	Avoidable cost of production, $	Plant name	Location	
3,124.00	36.21	E. I. Dupont De Nem	Deepwater	NJ
3,336.00	35.95	Army Ammunition Plt	Radford	VA
3,496.00	35.94	Allied Chemical Corp	Front Royal	VA
3,821.00	35.60	Royster Company	Mulberry	FL
4,021.00	35.50	Allied Chemical Corp	Hopewell	VA
4,271.00	35.06	Stauffer Chemical Co.	LeMoyne	AL
4,371.00	35.03	Monsanto Company	El Dorado	AR
4,446.00	34.40	LJ + M LaPlace Cde	Edison	NJ
4,896.00	34.17	Gardinier	Tampa	FL
5,161.00	34.04	Monsanto Company	E. St. Louis	IL
5,231.00	33.94	USS Agri-Chem	Wilmington	NC
5,551.00	33.81	W. R. Grace and Co.	Bartow	FL
5,731.00	33.20	Essex Chemical Co.	Newark	NJ
6,056.00	32.78	E. I. Dupont De Nem	Linden	NJ
6,276.00	32.73	Swift Chem Co.	Agricola	FL
6,401.00	32.51	Cities Service Oil	Augusta	GA
6,881.00	32.49	W. R. Grace and Co.	Bartow	FL
7,231.00	32.48	Olin Corporation	Baltimore	MD
7,351.00	32.30	Monsanto Company	Everett	MA
7,521.00	32.12	U.S. Industrial Chem	Tuscola	IL
7,970.00	31.76	Texasgulf Inc.	Lee Creek	NC
8,853.00	31.72	Gardinier	Tampa	FL
9,413.00	31.41	NL Industries Inc.	Sayreville	NJ
9,833.00	31.19	Mobil Oil	Depue	IL
10,288.00	31.12	NL Industries Inc.	St. Louis	MO
11,568.00	30.96	W. R. Grace and Co.	Bartow	FL
11,968.00	30.88	Engelhardt McConser	Nichols	FL
12,468.00	30.30	Olin Corporation	Pasadena	TX
13,825.00	30.30	Texasgulf Inc.	Lee Creek	NC
14,070.00	29.82	American Cyanamid	Warner (Linden)	NJ
14,286.00	29.80	American Cyanamid	Savannah	GA
14,816.00	29.75	American Cyanamid	Fortier	LA
15,096.00	29.12	USS Agri-Chem	Bartow	FL
16,146.00	28.56	Gardinier	Tampa	FL
17,346.00	28.45	Agrico Chem-Williams	Donaldsonville	LA
17,886.00	27.92	USS Agri-Chem	Ft. Meade	FL
18,376.00	27.60	Borden Chemical	Pt. Manatee	FL
18,901.00	27.53	Beker Industries	Taft	LA
20,121.00	27.27	Miss Chem Corp.	Pascagoula	MS
20,621.00	27.26	Allied Chemical Corp.	Geismar	LA
22,271.00	26.87	Occidental Ag Chem	White Springs	FL
23,497.00	26.50	Farmland Industries	Pierce	FL
24,687.00	26.35	CF Industries Inc.	Bonnie	FL
25,347.00	26.21	CF Industries Inc.	Bonnie	FL
26,897.00	25.85	CF Industries Inc.	Plant City	FL
28,097.00	25.64	Agrico Chem-Williams	Pierce	FL
30,257.00	25.23	Freeport Minerals	Uncle Sam	LA
32,237.00	25.19	International Miner	Bonnie	FL

TABLE G-2. DEMAND SCHEDULE FOR H_2SO_4 - WESTERN ACID PLANTS

Annual capacity, ktons	Avoidable cost of production, $	Plant name	Location	
15.00	43.72	Georgia Pacific	Bellingham	WA
156.00	37.61	Kerr-McGee	Grants	NM
191.00	34.29	Phelps Dodge	Jeffrey City	WY
246.00	33.83	Union Carbide Corp.	Uravan	CO
312.00	31.95	Valley Nitrogen Prod.	Bena	CA
452.00	30.43	Allied Chemical Corp.	Pittsburg	CA
527.00	30.00	Phelps Dodge	Riverton	WY
667.00	29.33	Anaconda Company	Yerington	NV
867.00	29.31	Allied Chemical Corp.	Richmond	CA
1,092.00	27.35	Occidental Ag Chem	Lathrop	CA
1,467.00	26.97	Valley Nitrogen Prod.	Helm	CA
1,732.00	26.45	Valley Nitrogen Prod.	Helm	CA
2,392.00	21.26	Beker Industries	Conda	ID
3,042.00	20.53	J. R. Simplot Co.	Pocatello	ID

APPENDIX H

BYPRODUCT H_2SO_4 PRODUCTION FROM SMELTER GASES INCLUDING ESTIMATES OF RETROFIT TAIL GAS CLEANUP AND LIMESTONE NEUTRALIZATION

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APPENDIX H

BYPRODUCT H_2SO_4 PRODUCTION FROM SMELTER GASES INCLUDING ESTIMATES OF RETROFIT TAIL GAS CLEANUP AND LIMESTONE NEUTRALIZATION

H_2SO_4 PRODUCTION FROM SMELTER GAS

Technology

As in an elemental S-burning acid plant, the SO_2 in the smelter gases is oxidized to SO_3 by the contact process to produce H_2SO_4. While the SO_2 gas stream to the converter in an elemental S acid plant is clean and requires little if any cleanup to protect the catalyst in the converter, the gases from smelter plants are dirty and require extensive treatment to remove dust and fume. Most of the dust and fume are removed in dry cyclones and bag filters. At this point the gas is discharged to the atmosphere if SO_2 removal is not necessary.

If the SO_2 is to be recovered in an acid plant, the remaining dust and fume must be removed, usually in a wet scrubber. In the scrubber the small amount of SO_3 formed during the smelting process reacts with the water to form a weak solution of H_2SO_4. Some of the acid formed leaves the scrubber as a mist and must be removed in an electrostatic precipitator (ESP). The weak acid from the scrubber and precipitator is contaminated with dust and is discarded. The cleaned gases, having been passed through a wet scrubber, are saturated with water vapor. Part of this water must be removed so that the ratio of water:SO_2 in the gas does not exceed that required to produce concentrated acid (100% H_2SO_4 has a water:SO_2 mol ratio of 1). The excess water is removed by cooling the gas directly by contact with product acid or indirectly in a water-cooled heat exchanger, or both. The cleaned and cooled gases are now ready for conversion of the SO_2 to H_2SO_4 in a conventional contact plant.

Economics

Smelter gas acid plants are more expensive to build and operate than S-burning plants, primarily because the smelter off-gases must be thoroughly cleaned before processing in the acid plant. Another factor is the varying SO_2 content of the several gas streams from a smelter, ranging from <1% from reverberatory copper smelting furnaces to about 15% from fluid-bed roasters. For technical and economic reasons, the SO_2 content of the gases fed to a contact acid plant is limited to the range of about 4-12%. The higher limit is imposed by the fact that the SO_2-bearing gases to the converter of a contact acid plant must contain sufficient oxygen to oxidize the SO_2 to SO_3. Also, as the SO_2 content of the gases increases, the amount of heat released by the oxidation of SO_2 to SO_3 in the converter increases and the resulting higher temperature may damage the catalyst. The lower limit is imposed by economic considerations. Concentrations of SO_2 lower than 4% in the feed gas are technically feasible but uneconomic because to accommodate the larger gas flows necessary to maintain a reasonable production rate, the size of the equipment, and thus its cost, become prohibitive. Some of the gas streams from a smelter may be blended to give a composition suitable for feeding to an acid plant, but even so, some of the dilute SO_2 gases are vented to the atmosphere after particulate removal when SO_2 emission standards permit.

The above considerations make it desirable to have cost data for several sizes of smelter acid plants, each receiving feed gases of varying SO_2 content. Hence, cost estimates were prepared for smelter acid plants having capacities of 250, 750, and 1500 tons of 100% H_2SO_4/day, operating 330 days/yr, and processing gases containg 4, 8, and 12% SO_2. Costs were calculated as of the third quarter of 1974 and mid-1978.

The capital and operating cost data were obtained primarily from System Study for Control of Emissions - Primary Nonferrous Smelting Industry by Arthur G. McKee and Company, San Francisco, California, June 1969. The capital investments for these plants include, in addition to the acid plant itself, only the gas cleaning and cooling equipment required to protect the catalyst in the acid plant converter; the cost of the preliminary gas-cleaning equipment required to meet particulate emission standards is a necessary cost for processing those gas streams which are to be vented to the atmosphere without SO_2 removal, and thus, is not considered as an expense chargeable to SO_2 recovery.

Since most of the existing smelter acid plants are of the single contact-single absorption type, this technology was used in preparing the cost estimates. Costs for retrofitting these plants to meet acid plant emission standards will be found in the appendix of this report.

Discussion of Results

The data in Table H-1 indicate that unit capital investment decreases both with increased acid plant size and with increased concentration of SO_2 in the feed gases. The unit capital cost in \$/ton of 100% H_2SO_4/yr for the third quarter of 1974 decreases from \$106.19 for a 250 ton/day plant receiving gases containing 4% SO_2 to \$68.82 for a 1500 ton/day plant also receiving 4% SO_2 gases. Similar trends occur for plants processing 8 and 12% SO_2 gases. The unit capital cost decreases from the \$106.19 figure mentioned above for a 250 ton/day plant being fed gases containing 4% SO_2 to \$61.05/ton of 100% H_2SO_4/yr for the same sized plant processing 12% SO_2 gases.

Operating costs in \$/ton of 100% H_2SO_4 also decrease with increasing size of acid plants and increasing concentration of SO_2 in the feed gases as shown in Table H-2. The operating cost for a 250 ton/day plant processing 4% SO_2 gases is \$24.79/ton of 100% H_2SO_4 for third quarter 1974 costs, while the operating cost for a 1500 ton/day plant, also processing 4% SO_2 gases, is \$14.38. When the concentration of SO_2 in the feed gases is increased to 12%, the operating cost for the 250 ton/day plant processing 4% SO_2 gases decreases from the \$24.79 figure to \$14.44 for the same sized plant processing 12% SO_2 gases. The trends illustrated above also apply to the mid-1978 data.

TABLE H-1. H_2SO_4 PRODUCTION FROM SMELTER GAS - EFFECT OF ACID PLANT CAPACITY ON TOTAL CAPITAL INVESTMENT AT VARIOUS SO_2 LEVELS IN SMELTER GAS

Acid plant capacity, tons of 100% H_2SO_4/day	Total capital investment, $			Capital investment, $/ton 100% H_2SO_4/yr		
	4% SO_2	8% SO_2	12% SO_2	4% SO_2	8% SO_2	12% SO_2
Third Quarter 1974 Costs						
250	8,760,960	5,513,230	5,036,900	106.19	66.82	61.05
750	19,891,100	12,460,300	11,791,700	80.37	50.34	47.64
1,500	34,065,850	21,119,390	19,281,110	68.82	42.67	38.95
Mid-1978 Costs						
250	11,258,000	7,084,500	6,472,400	136.46	85.87	78.45
750	25,560,000	16,011,500	15,152,300	103.27	64.69	61.22
1,500	43,774,600	27,138,400	24,776,200	88.43	54.83	50.05

TABLE H-2. H_2SO_4 PRODUCTION FROM SMELTER GAS - EFFECT OF ACID PLANT CAPACITY ON OPERATING COST AT VARIOUS SO_2 LEVELS IN SMELTER GAS

Acid plant capacity, tons of 100% H_2SO_4/day	Operating cost, $/ton 100% H_2SO_4		
	4% SO_2	8% SO_2	12% SO_2
Third Quarter 1974 Costs			
250	8.34	3.87	2.38
750	6.45	2.96	1.80
1,500	5.06	2.30	1.38
Mid-1978 Costs			
250	12.37	5.74	3.54
750	9.76	4.53	2.76
1,500	8.08	3.68	2.22

RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING SMELTER GAS

Technology

Smelter gas H_2SO_4 plants can be retrofitted for control of tail gas emissions using the technology previously discussed in this report in the section on retrofitting elemental S-burning plants. The information developed in that section of the report showed that for all the acid plant sizes investigated, the dual contact-dual absorption alternative had the lowest overall average operating cost. For this reason only the dual contact-dual absorption system was evaluated for use on smelter gas acid plants.

Economics

In S-burning acid plants the gas to the converter contains about 8% SO_2. Since retrofitting costs have been developed for such plants in a prior section of this report, these developed capital costs are used directly as the capital costs for retrofitting smelter gas acid plants also being fed gases containing 8% SO_2. The capital costs for smelter gas (or other) acid plants are directly proportioned to gas flow. For a given acid production rate gas flow translates inversely to SO_2 content. Hence the capital costs for smelter gas acid plants being fed gas streams containing 4% and 12% SO_2 were calculated from the costs of acid plants being fed 8% SO_2 using appropriate scaling factors.

Costs for retrofitting smelter gas acid plants with dual contact-dual absorption systems having capacities of 250, 750, and 1500 tons of 100% H_2SO_4/day and being fed gases containing 4%, 8%, and 12% SO_2 were estimated for the third quarter of 1974 and mid-1978.

Discussion of Results

The data in Table H-3 show the same trend in unit capital costs for retrofitting smelter gas acid plants with dual contact-dual absorption systems as the data for capital costs of the smelter gas acid plants themselves. The unit capital investment required decreases as the size of the plant and the concentration of SO_2 in the feed gases increases. For example, the unit capital investment in the third quarter of 1974 for a 250 ton/day plant receiving gases containing 8% SO_2 is \$13.87/ton of 100% H_2SO_4 produced/yr while a 1500 ton/day plant requires only \$6.91. The third quarter 1974 unit investment cost for a 250 ton/day plant is \$28.94/ton of 100% acid/yr when the feed gas contains 4% SO_2 while the corresponding cost when the feed gas contains 12% SO_2 is \$8.45.

Operating costs show the same trend. In the third quarter of 1974, the operating costs for a 250 ton/day plant processing gases containing 8% SO_2 is \$3.87/ton of 100% H_2SO_4 while the corresponding cost for a 1500 ton/day plant is \$2.30. When a 250 ton/day plant processes gases containing 4% SO_2, the operating cost is \$8.34/ton of 100% H_2SO_4 while the cost of processing gases containing 12% SO_2 is \$2.38. These trends for both unit capital and operating costs are also reflected in the mid-1978 costs.

TABLE H-3. RETROFIT OF EMISSION CONTROLS TO H_2SO_4 PLANTS USING SMELTER GAS - DUAL CONTACT-DUAL ABSORPTION SYSTEM - EFFECT OF ACID PLANT CAPACITY ON TOTAL CAPITAL INVESTMENT AT VARIOUS SO_2 LEVELS IN SMELTER GAS

Acid plant capacity, tons of 100% H_2SO_4/day	Total capital investment, \$			Capital investment, \$/ton 100% H_2SO_4/yr		
	4% SO_2	8% SO_2	12% SO_2	4% SO_2	8% SO_2	12% SO_2
Third Quarter 1974 Costs						
250	2,387,530	1,144,000	729,900	28.94	13.87	8.45
750	5,296,800	2,538,000	1,619,240	21.40	10.25	6.54
1,500	7,133,400	3,418,000	2,180,700	14.41	6.91	4.41
Mid-1978 Costs						
250	3,068,000	1,470,000	937,900	37.19	17.82	11.37
750	6,663,400	3,261,300	2,080,700	26.92	13.18	8.41
1,500	9,166,400	4,392,100	2,802,200	18.52	8.87	5.66

LIMESTONE NEUTRALIZATION OF H_2SO_4

Technology

At the present time no detailed information is available concerning large-scale neutralization of H_2SO_4. Therefore, the information given in this report is based on a conceptual design and cost study presented in Neutralization of Abatement Derived Sulfuric Acid prepared for EPA by Process Research, Inc., EPA Report No. EPA-R2-73-187. In this conceptual design, the H_2SO_4 is neutralized with a slurry of ground limestone. The resulting gypsum is disposed of by ponding.

The ground limestone is slurried with the overflow from the gypsum pond. The slurry is pumped to a neutralization tank where the acid is added. The gases evolved (mostly CO_2) are vented to the atmosphere through the limestone slurry tank to trap any SO_3 vapor which might be liberated by the heat generated during the neutralization step. The neutralized slurry is pumped to the gypsum settling pond where the remaining heat of reaction is dissipated by the evaporation of water from the pond. The overflow from the pond is collected in a sump where makeup water is added to compensate for that lost in evaporation and for that occluded or combined in the gypsum sludge. The amount of makeup water required will be reduced in proportion to the rainfall collected by the pond. The strength of the acid neutralized will also affect the water balance. In this study, 93% H_2SO_4 is neutralized. However, except in the wettest regions of the U.S., such as the Gulf Coast, the amount of water lost from the circuit by evaporation and by retention in the gypsum sludge will exceed the amount added by rainfall, making the use of makeup water necessary. This may occur during the dry season in the arid regions of the West where the neutralization of smelter acid may become important because of the lack of markets for the abatement acid. However, in this study, it is assumed that neither will makeup water be required, nor will disposal of surplus water be necessary.

The gypsum pond dikes are constructed of soil excavated from the interior area. The bottoms of the ponds and the inside slopes of the dikes are covered with a 6-in. layer composed of selected excavation materials into which bentonite has been mixed. Another 4- to 6-in. layer of excavated material is placed on top of the bentonite-treated layer. The outside faces and tops of the dikes are finished with a layer of topsoil. The pond overflow is collected in a structure located opposite the slurry inlet and includes an adjustable weir gate and a sump containing a pump. The pond or ponds are all 20 ft deep. No acid storage facilities are included in the system since the acid storage associated with the acid plants is assumed to be adequate.

Economics

The conceptual design used in this report is essentially the same as the one appearing in the previously mentioned report Neutralization of Abatement Derived Sulfuric Acid. The Process Research report assumed the initial purchase of land for 10 annual gypsum ponds and the construction of only one annual pond; however, a single 30-yr pond concept was used in this report.

Investment and operating costs were calculated for neutralization facilities having daily capacities of 250, 750, and 1500 tons/day of 100% H_2SO_4 and operating 330 days/yr. The 1500 ton/day unit was assumed to have two neutralization tanks and dual ball mills for grinding the limestone; the other units have a single neutralization tank and one ball mill. Costs were calculated for the third quarter of 1974 and mid-1978.

Discussion of Results

The data in Table H-4 indicate that, as might be expected, the economies of size are present in this operation; that is, as the size of the facility increases, both the unit investment and operating cost decrease. For a neutralizing system treating 250 tons/day of 100% H_2SO_4, the unit investment cost in the third quarter of 1974 is \$84.74/ton of 100% H_2SO_4/yr and the operating cost is \$25.13/ton of 100% H_2SO_4 neutralized, while for a 1500 ton/day installation the comparable figures are \$38.52 and \$12.95. The costs for mid-1978 show a similar trend.

Since the gypsum pond accounts for about 80% of the capital investment, oth the investment costs and the operating costs will be reduced considerably

when a neutralization plant is built for an acid plant which has only 10- or 15-yr life expectancy and is not scheduled for replacement.

TABLE H-4. LIMESTONE NEUTRALIZATION OF H_2SO_4 -

EFFECT OF SYSTEM CAPACITY ON TOTAL CAPITAL

INVESTMENT AND OPERATING COST

System capacity, tons of 100% H_2SO_4 neutralized/day	Total capital investment, $	Capital investment, $/ton 100% H_2SO_4/yr	Operating cost, $/ton 100% H_2SO_4
Third Quarter 1974 Costs			
250	6,991,300	84.74	25.13
750	13,029,200	52.64	16.60
1,500	19,067,100	38.52	12.95
Mid-1978 Costs			
250	8,983,800	108.89	34.28
750	16,742,500	67.65	23.21
1,500	24,501,200	49.50	18.40

APPENDIX I

H_2SO_4 TRANSPORTATION RATES FROM WESTERN SMELTERS TO EASTERN TERMINALS

CONTENTS

Table — Page

I-1 Unit Train H_2SO_4 Rates, $/Ton 182

TABLE I-1. UNIT TRAIN H_2SO_4 RATES, \$/TON[a]

Point of origin							Eastern terminals	
Hayden AZ	Hurley NM	Separ NM	Kellogg ID	Anaconda MT	Garfield UT	Canada	Location	
21.80	16.79	16.79	22.05	19.00	18.75	-	Chicago	IL
24.42	18.86	18.86	22.95	19.40	17.85		St. Louis	MO
24.42	18.86	18.86	22.95	19.40	17.85		Memphis	TN
24.42	18.86	18.86	41.85	35.65	30.50	-	Baton Rouge	LA
19.60	13.36	13.36	41.85	33.15	26.50	-	Houston	TX
-	-	-	-	-	-	5.45	Buffalo	NY
-	-	-	-	-	-	6.85	Detroit	MI

a. A terminal handling charge of \$1.50/ton will be added at each terminal.

APPENDIX J

PROJECTION OF STEAM PLANT DATA BASE, 1978

APPENDIX J

PROJECTION OF STEAM PLANT DATA BASE, 1978

FPC Form 67 was the basic data source used in developing the steam plant data base and converting the information into a form useful for calculation of scrubbing cost by any of the processes considered. Projections for 1978 made by the utilities were taken as accurate projections of power demand in 1978 for each plant.

Many of the projections made by the industry and reported to FPC were plant level projections. To calculate scrubbing cost it was necessary to convert plant level data to boiler level. Specific data requirements necessary to calculate costs included boiler age, air rate, heat rate, boiler size, and fuel type, quantity, Btu content, and S content.

Boiler age and size were given for each plant. For new plants boiler age was obtained from other FPC reports.

Fuel Projections

The FPC data from Form 67 only reported megawatts to be generated and fuel consumption at the plant level. For purposes of cost estimation it was necessary to convert plant level projections to boiler level projections of fuel use by type and amount. Normally Btu content and S content of fuels to be used were given. When no values were given, the following standard values were assumed: S content of fuel, coal 3.5%, oil 2.5%, gas 0%; Btu content of fuel, coal 12,000 Btu/lb, oil 149,000 Btu/gal, and gas 1,000 Btu/ft^3. In some cases plant projections for 1978 were not made. The following briefly describes the methods and procedures followed to develop fuel projections to be used in the steam plant data base.

In some cases boilers were listed as existing that apparently were no longer in service except possibly on a standby basis. That is, the sum of reported boiler capacity exceeded reported plant capacity. Recognizing that scrubbing facilities would not be installed on these unused boilers, they were dropped from consideration. The procedure for dropping was to eliminate any boiler >30 yr old that had a capacity equal to or less than the difference between boiler capacity and plant capacity when boiler capacity was greater than plant capacity. After this algorithm was completed, all remaining boilers were considered candidates for scrubbing.

Boilers are used at <100% of capacity, depending on a number of factors including power demand. Projections made by the utilities were assumed to reflect power demand in 1978. Boiler age is the most general determinant of using the boiler or its capacity factor. The projected boiler capacity factor was used as the key factor in allocating fuel input requirements to individual boilers. The capacity factor used was based on historical (1969-73) capacity factor versus age of reported boiler operation. That relationship is shown in Figure 16. It represents the average capacity factor of each boiler for the 5-yr period (about 15,000 observations). This relationship was used to predict boiler capacity factor as a function of age. The data indicated a startup period lasting for about 10 yr. During this period, the relationship was assumed linear and positive of the type $y = a + bx$. Boilers going on stream in 1978 are assumed to operate at a capacity factor of 50%. Operation is assumed to increase at an annual rate of 1.5% through 10 yr of age. Between ages 10 and 15, operation is assumed constant at a 65% capacity factor. After age 15, the capacity factor is assumed to decline linearly at an annual rate of 1.8%/yr to a minimum of 2% at 50 yr by the equation $y = a + bx$.

Once boiler capacity (given from FPC) and its capacity factor were established it was then possible to calculate megawatts to be generated by each boiler and to calculate Btu of heat input required. This calculation was based on the given or the assumed plant heat rate.

At this point, two algorithms were used. If a plant had projected its own megawatt production and fuel level, the projection by the utility was assumed correct. If fuel requirements at the boiler level, based on calculated capacity factors, were less than plant level projections of megawatts to be generated by the plant, each boiler capacity factor was adjusted upward by a constant percentage. If fuel requirements exceeded plant megawatt projections, then boiler capacity factors were adjusted downward by a constant percentage. If a 30-yr-old or older boiler existed and plant megawatt could be generated by existing newer boilers at the calculated capacity factor, the capacity factor of the old boiler was reduced to zero. (No fuel was allocated to those boilers.)

When the utility did not project megawatts to be generated and/or fuel use in 1978, each boiler was assumed to operate at the calculated capacity factor based on boiler age. Megawatts to be generated and fuel requirements were calculated accordingly.

Completion of the above steps provided an estimate of total Btu heat input requirements to meet projected 1978 power demands. Btu requirements were, at the same time, projected to each individual boiler to be used in generating electricity in 1978. The next step was to calculate fuel type and amount to meet projected Btu requirements.

Plant Level Fuel Type, 1978

When plant level projections of fuel requirements were made, fuel type and Btu content were also given and usually S content of each fuel was also given. Five separate cases were identified requiring slightly different procedures to project fuel type and amount. In all cases, amount of fuel is a function of Btu content of the fuel and Btu heat input requirements.

Case 1

This case covers all plants that reported 1973 data and that projected fuel on Form 67. When the plant level projections for 1978 were made on Form 67, they were assumed to be correct in all cases except when the quantities of fuel projected would cause the plant to exceed megawatt capacity. Where fuel quantities would cause the plant to exceed the reported capacity, fuel quantities were reduced proportionally to operate the plant at 80% of reported capacity. There were 625 plants in this category. In this and all other cases projected megawatts to be generated were used as the factor to check against and adjust to if fuel projections and megawatts to be generated did not match.

Case 2

This case covers all plants existing in 1973 that reported plant level fuel consumption in 1973, but did not project megawatts to be generated or fuel quantities in 1978, and did not project an increase of >100 MW of capacity between 1973 and 1978. The historical capacity factor profile presented earlier is used to calculate megawatts to be generated and Btu heat input requirements. The proportion of the total projected Btu requirements to be met from each fuel source is assumed to be the same as used in 1973. There were 107 plants included in this category.

Case 3

This is the same as Case 2 above except that it considers plants where capacity has increased by >100 MW between 1973 and 1978. Fuel consumption in 1978 on the capacity existing in 1973 is calculated the same as in Case 1 above. Additional fuel consumption for the new increased capacity will be based on the projected capacity factor as in Case 2, and the fuel type will be determined as follows: If the plant burned oil in 1973, but no coal, the additional fuel will be oil; otherwise, the additional fuel will be coal. There were seven plants included in this category.

Case 4

This case covers all new plants coming online after 1973 that did not report 1973 data, and did not project megawatts or fuel consumption for 1978. They are projected to burn coal and to operate at the projected capacity factor based on the historical data. There were 43 plants included in this category.

Case 5

This case covers all new plants (coming online after 1973) that did project megawatts to be generated and fuel consumption for 1978. This is the same as Case 1, but a separate case number was used to allow identification of new plants. There were 18 plants included in this category.

Once these calculations were completed, Btu input requirements per boiler had been established. The remaining problem was to determine what fuel type each boiler will use when the plant projects more than one fuel type. It will be recalled that when fuel type was not projected, only coal or oil was projected as a fuel source and in no case were fuel sources mixed. Oil was projected only if the plant had never burned coal in any boiler from 1969-73. Where projections of mixed fuel sources were made, an algorithm was developed to allocate all projected gas consumption first. Gas was first projected to the largest exclusive gas boiler. If that did not take up all gas then remaining, gas was allocated to boilers that had historically used gas until projected consumption was met. Oil was allocated next in the same fashion as gas. First to largest exclusive oil boiler, and so on, until all projected oil was consumed. Coal was allocated last as above to the largest exclusive coal boilers and as needed to fill any remaining need for Btu heat input requirements at any boiler. The steam plant data base is complete at this point.

Historical and projected 1978 fuel usage by type is shown in the following tabulation:

Actual Fuel Use by Type (1969-73) and Projected Use by Type (1978)

Year	Coal, ktons	Oil, k (42-gal) bbl	Gas, Mft^3
1969	30,379	252,654	3,319,330
1970	314,749	323,291	3,704,726
1971	324,271	377,030	3,728,747
1972	348,694	458,390	3,707,278

APPENDIX K

VARIABLE COST OF LIMESTONE AND SLUDGE DISPOSAL

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APPENDIX K

VARIABLE COST OF LIMESTONE AND SLUDGE DISPOSAL

The delivered cost of limestone is a major input cost item and is subject to wide variation due to availability and f.o.b. cost of limestone. A 1972 study (Availability of Limestones and Dolomites - Task No. 1 Final Report, by J. J. O'Donnell and A. G. Sliger of the M. W. Kellogg Company) estimated delivered cost of high-Ca limestone in 1972 to 37 selected power plants, most of which were located in the eastern half of the U.S. Delivered costs ranged from \$1.95-\$13.00/ton. Delivered costs were under \$4/ton to half the plants and all but three in the study could have been supplied at under \$6/ton. Previous TVA studies had assumed limestone cost at \$4/ton to each utility. Because of the variability in cost found in the Kellogg study previously mentioned, a limestone data base was developed to use in this and other studies. This data base provides for the calculation of delivered cost of limestone to each utility from the nearest limestone quarry. The f.o.b. price used is the state average price in 1975 inflated by 10% to reflect 1978 costs. Dolomite sources are excluded from the data base. According to information developed, delivered costs of limestone in 1978 will range from \$2.07-\$11.23/ton. All but 50 plants in the U.S. can be supplied at a delivered cost of <\$6/ton in 1978.

The data do not assure that limestone is of the quality required for use in scrubbing. Further, there is no assurance that sufficient quantities exist at producing locations to meet long-term utility needs.

The limestone data base was developed from information provided specifically for use in this study by BOM.

A few existing plants do not have adequate land available for onsite disposal of throwaway Ca solids from the slurry process. When this was the case, offsite disposal charges were added. Land cost was assumed the same. Some cost areas were different between onsite and offsite disposal but in sum total investment was approximately equal. Miles to disposal area were added into the cost model and transportation costs were calculated. Costs were based on a charge of \$1/ton for distances up to 3 mi and then charges were assumed to decline linearly to a minimum of \$0.20/ton mi for distances up to 20 mi.

The calculated delivered costs of limestone are shown in the following tabulation for selected power plants.

Plant No.	Plant name	MW	Mine price, $/ton	Transport cost, $/ton	Delivered cost, $/ton
0700000550	Roseton	1,200	2.66	1.61	4.27
0785000100	Coffeen	616	2.37	1.15	3.52
0785000500	Newton	590	2.37	1.61	3.98
0790000100	Edwards	602	2.37	2.07	4.44
1000000050	Deely	836	2.21	1.15	3.36
1095000200	Conesville	1,255	2.41	1.61	4.02
1115001300	Powerton	1,271	2.37	1.61	3.98
1395000250	Belews Creek	2,286	2.44	2.30	4.44
1655000300	Crystal River	964	2.06	1.61	3.67
1790002550	Wansley	1,792	2.67	2.07	4.74
1790002800	Bowen	1,820	2.67	1.15	3.82
2455000250	Ghent	1,011	2.22	1.15	3.37
2730000600	Northport	1,511	8.24	2.30	10.54
3795000350	Homer City	650	2.62	1.61	4.23
3800000800	Martins Creek	1,600	2.62	1.15	3.77
3840000500	Eddystone	940	2.62	1.61	4.23
4045000900	Cayuga	1,062	2.22	2.07	4.29
4510000100	Gaston	910	2.39	1.15	3.54
4530000850	Harrington	634	1.90	2.07	3.97
4740000300	Big Bend	1,136	2.06	2.07	4.13
4770001900	Johnsonville	1,482	2.35	2.30	4.65
4770002100	Kingston	1,723	2.24	2.07	4.31
4770003000	Paradise	2,558	2.35	1.15	3.50
4770004100	Cumberland	2,660	2.35	2.07	4.42
4815000400	Stuart	1,831	2.41	1.61	4.02
5125000650	Rush Island	1,150	2.37	1.61	3.98
5125000700	Sioux	1,100	2.37	1.61	3.98
5250001400	Yorktown	845	2.44	3.45	5.89
5540000250	Columbia	527	1.91	1.15	3.06

APPENDIX L

SPECIFIC SUPPLY POINTS FOR SALE OF BYPRODUCT SMELTER ACID

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TABLE L-1 FOURTEEN WESTERN SMELTERS

No.	Company	Location		Capacity
065	Gulf Resources	Kellogg	ID	250,000
150	Phelps Dodge	Morenci	AZ	600,000
151	Kennecott Copper	Hayden	AZ	250,000
152	American Smelting (ASARCO)	Hayden	AZ	260,000
153	Phelps Dodge	Ajo	AZ	100,000
154	Magma Copper Company	San Manual	AZ	525,000
155	Hecla Mining Company	Casa Grande	AZ	89,000
156	Inspiration Con Corp	Inspiration	AZ	460,000
157	Anaconda Company	Anaconda	MT	230,000
158	Kennecott Copper	Hurley	NM	200,000
159	Kennecott Copper	Garfield	UT	600,000
160	American Smelting (ASARCO)	Tacoma	WA	50,000
175	Anaconda Company	Anaconda	MT	100,000
182	Phelps Dodge	Hidalgo Co.	NM	580,000
	Total			4,294,000

TABLE L-2. EASTERN SMELTERS SELLING BYPRODUCT ACID IN $0.00 AND $0.35/MBTU ACFL RUNS

Company	Location		Tons sold
New Jersey Zinc Company	Palmerton	PA	26,000
St. Joe Minerals	Herculaneum	MO	14,000
American Smelting (Asarco)	Corpus Christi	TX	7,000
American Metal (Amax)	Monsanto	IL	12,000
Amax Lead Company	Salem (Buick)	MO	7,000
Engelhard-Nat'l Zinc	Bartlesville	OK	9,000
St. Joe Minerals	Josephtown	PA	54,000
Cities Service Oil	Copperhill	TN	200,000
American Smelting (Asarco)	El Paso	TX	16,000
American Metal (Amax)	Monsanto	IL	288,000
American Smelting (Asarco)	Corpus Christi	TX	76,000
Armco Steel	Middleton	OH	2,000
Climax Molybdenum	Langeloth	PA	47,000
Climax Molybdenum	Ft. Madison	IA	60,000
Total (14 Eastern Smelters)			818,000
Average			58,428

CANADIAN SMELTERS

Terminal	Tons sold
Buffalo	165,000
Detroit	35,000
Total	200,000

WESTERN SMELTERS

State	Terminal	Tons sold
Arizona	Houston	118,000
New Mexico	Chicago	304,000
	Baton Rouge	76,000
Utah	Memphis	96,000
Montana	St. Louis	46,000
	Memphis	98,000
Total		738,000

TOTAL SMELTER ACID

East	818,000
West	738,000
Canada	200,000
Total	1,756,000

TABLE L-3. SMELTERS SELLING BYPRODUCT ACID

IN $0.50/MBTU ACFL RUN

Company	Location		Tons sold
New Jersey Zinc	Palmerton	PA	26,000
St. Joe Minerals	Herculaneum	MO	14,000
American Smelting (Asarco)	Corpus Christi	TX	7,000
American Metal (Amax)	Monsanto	IL	12,000
Amax Lead Company	Salem (Buick)	MO	7,000
Engelhard-Nat'l Zinc	Bartlesville	OK	9,000
St. Joe Minerals	Josephtown	PA	54,000
Cities Service Oil	Copperhill	TN	200,000
American Smelting (Asarco)	El Paso	TX	16,000
American Metal (Amax)	Monsanto	IL	288,000
American Smelting (Asarco)	Corpus Christi	TX	76,000
Armco Steel	Middleton	OH	2,000
Climax Molybdenum	Langeloth	PA	47,000
Climax Molybdenum	Ft. Madison	IA	60,000
Total (14 Eastern Smelters)			818,000
Average			58,428

CANADIAN SMELTERS

Terminal	Tons sold
Buffalo	200,000
Detroit	0
Total	200,000

WESTERN SMELTERS

State	Terminal	Tons sold
Arizona	Houston	118,000
New Mexico	Chicago	155,000
	St. Louis	166,000
	Baton Rouge	50,000
	Houston	9,000
Utah	St. Louis	96,000
Montana		0
Total		594,000

TOTAL SMELTER ACID

East	818,000
West	594,000
Canada	200,000
Total	1,612,000

TABLE L-4. SMELTERS SELLING BYPRODUCT ACID IN $0.70/MBTU ACFL RUN

Company	Location		Tons sold
New Jersey Zinc	Palmerton	PA	26,000
St. Joe Minerals	Herculaneum	MO	14,000
American Smelting (Asarco)	Corpus Christi	TX	7,000
American Metal (Amax)	Monsanto	IL	12,000
Amax Lead Company	Salem (Buick)	MO	7,000
Engelhardt-Nat'l Zinc	Bartlesville	OK	9,000
St. Joe Minerals	Josephtown	PA	54,000
Cities Service Oil	Copperhill	TN	200,000
American Smelting (Asarco)	El Paso	TX	16,000
American Metal (Amax)	Monsanto	IL	288,000
American Smelting (Asarco)	Corpus Christi	TX	76,000
Armco Steel	Middleton	OH	2,000
Climax Molybdenum	Langeloth	PA	47,000
Climax Molybdenum	Ft. Madison	IA	60,000
Total (14 Eastern Smelters)			818,000
Average			58,428

CANADIAN SMELTERS

Terminal	Tons sold
Buffalo	200,000
Detroit	0
	200,000

WESTERN SMELTERS

State	Terminal	Tons sold
Arizona	Houston	118,000
New Mexico	Chicago	81,000
Utah		0
Montana		0
Total		199,000

TOTAL SMELTER ACID

East	818,000
West	199,000
Canada	200,000
Total	1,217,000

APPENDIX M

SCRUBBING VERSUS CLEAN FUEL WHEN ACFL IS $0.70/MBTU HEAT INPUT

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L-2 Estimated Compliance Strategies for the Western States 201

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TABLE M-1. ESTIMATED COMPLIANCE STRATEGIES FOR THE THIRTY-SEVEN EASTERN STATES SCRUBBING VERSUS CLEAN FUEL WHEN ACFL IS $0.70/MBTU HEAT INPUT

	Scrubbed (≤70¢)			Clean fuel (>70¢)		
		Abatement capacity, ktons			Abatement capacity, ktons	
State	No. of plants	S	H_2SO_4	No. of plants	S	H_2SO_4
AL	4	100,806	308,769	0		
DE	2	11,242	34,434	0		
DC	0		0	2	1,875	5,743
FL	4	163,465	500,693	4	2,227	6,821
GA	2	166,304	509,389	0		
IL	6	240,584	736,909	5	9,183	28,128
IN	13	480,422	1,471,533	12	49,619	151,983
IA	1	8,376	25,656	2	2,957	9,057
KS	0		0	1	5,253	16,090
KY	8	464,708	1,423,401	5	26,317	80,609
LA	0		0	1	2,074	6,353
ME	1	6,533	20,011	0		
MD	3	32,845	100,604	1	707	2,166
MA	1	6,983	21,389	1	3	9
MI	7	217,950	667,581	4	30,402	93,121
MN	0		0	1	161	493
MS	3	48,286	147,900	0		
MO	4	125,383	384,048	2	941	2,882
NH	1	10,735	32,881	0		
NJ	4	49,299	151,003	2	1,709	5,235
NY	5	86,574	265,176	4	11,114	34,042
NC	2	45,781	140,227	0		
ND	1	22,324	68,378	0		
OH	13	845,395	2,589,445	15	57,046	174,731
OK	1	8,241	25,242	1	86	263
PA	10	207,503	635,582	6	10,965	33,585
SC	1	13,728	42,049	1	1,491	4,567
TN	5	499,036	1,528,547	1	5,071	15,532
TX	4	92,838	284,363	0		
VA	2	28,135	86,178	0		
WV	4	85.107	260,683	1	14	43
WI	1	9,878	30,256	3	2,383	7,299
	113[a]	4,078,461	12,490,286	75[a]	223,686	685,038

[a] Ten plants are scrubbing and using clean fuel.

TABLE M-2. ESTIMATED COMPLIANCE STRATEGIES FOR THE WESTERN STATES SCRUBBING VERSUS CLEAN FUEL WHEN ACFL IS \$0.70/MBTU HEAT INPUT

	Scrubbed (≤\$0.70)			Clean fuel (>\$0.70)		
		Abatement capacity, ktons			Abatement capacity, ktons	
State	No. of plants	S	H_2SO_4	No. of plants	S	H_2SO_4
AZ	0			2	4,443	13,609
CA	0			1	317	971
NV	2	14,794	45,314	1	307	940
NM	0			1	70	214
WA	0			1	26	80
WY	1	15,708	48,114	0		
Total	3	30,502	93,413	6	5,163	15,812
East & West	116[a]	4,108,963	12,583,699	81[a]	228,849	700,850

[a] Ten plants are scrubbing and using clean fuel.

APPENDIX N

FEEDSTOCK ANALYSIS FOR S-BURNING H_2SO_4 PLANTS IN MODEL RUNS

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N-4 Acid Plants Buying Abatement Byproduct Acid in $0.70/MBtu ACFL Model Run 208

N-5 Acid Plants Buying Abatement Byproduct Acid and Frasch S in $0.00/MBtu ACFL Model Run 209

N-6 Acid Plants Buying Abatement Byproduct Acid and Frasch S in $0.35/MBtu ACFL Model Run 210

N-7 Acid Plants Buying Abatement Byproduct Acid and Frasch S in $0.50/MBtu ACFL Model Run 211

N-8 Acid Plants Buying Abatement Byproduct Acid and Frasch S in $0.70/MBtu ACFL Model Run 212

N-9 Fifty-Eight Acid Plants Buying Frasch S Only in $0.00/MBtu ACFL Model Run 213

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N-11 Thirty Acid Plants Buying Frasch S Only in $0.50/MBtu ACFL Model Run 215

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N-15 Set III - $0.50/MBtu ACFL Model Run 219

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TABLE N-1. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID

IN $0.00/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Steam plants	Smelters	Port Sulphur	Avoidable production cost
15	American Cyanamid	Bound Brook	NJ	65,000	1945		65,000	0	46.19
16	American Cyanamid	Mobile	AL	26,000	1967		26,000	0	41.19
17	American Cyanamid	Joliet	IL	50,000	1937		50,000	0	44.08
19	American Cyanamid	Kalamazoo	MI	25,000	1967		25,000	0	46.96
27	Army Ammunition	Tyner	TN	132,000	1941		132,000	0	38.42
32	Borden Chemical	Streator	IL	40,000	1951		40,000	0	44.70
44	Detroit Chemical	Detroit	MI	35,000	1937		35,000	0	57.91
51	E. I. Dupont	Cornwell Hghts	PA	75,000	1941		65,000	10,000	38.91
52	Eastman Kodak	Rochester	NY	6,000	1930		6,000	0	90.47
60	W. R. Grace	Joplin	MO	98,000	1954		7,000	91,000	39.68
68	Kerr-McGee	Cottondale	FL	15,000	1950		15,000	0	56.44
72	Minn Mine & Smelt	Copley	OH	65,000	1942		65,000	0	50.35
75	Monsanto Company	E. St. Louis	IL	265,000	1937		265,000	0	34.04
79	NL Industries	St. Louis	MO	455,000	1958		95,000	360,000	31.12
85	Olin Corporation	N. Little Rock	AR	105,000	1947		105,000	0	44.27
88	Olin Corporation	Pasadena	TX	500,000	1946		118,000	382,000	30.30
91	Pennsalt Chemicals	Tulsa	OK	110,000	1937		9,000	101,000	40.44
95	Reichhold Chemical	Tuscaloosa	AL	55,000	1957		55,000	0	39.15
98	Royster Company	Norfolk	VA	20,000	1937		20,000	0	51.70
104	Stauffer Chem	Ft. Worth	TX	120,000	1925		83,000	37,000	37.68
107	Swift Chemicals	Calumet City	IL	40,000	1942		40,000	0	45.66
108	Swift Chemicals	Wilmington	NC	32,000	1942		32,000	0	45.25
113	US Industrial	Dubuque	IA	98,000	1940		93,000	5,000	38.05
114	US Industrial	Desoto	KS	105,000	1940		60,000	45,000	40.29
126	American Cyanamid	Fortier	LA	50,000	1967		50,000	0	40.31
128	Home Guano Co	Dothan	AL	11,000	1937		11,000	0	66.35
130	Columbia Nitrogen	Moultrie	GA	24,000	1947		24,000	0	49.31
132	Marion Mfg	Indianapolis	IN	56,000	1947		56,000	0	44.82
133	E. I. Dupont	Gibbstown	NJ	110,000	1957		20,000	90,000	40.52
135	Cities Service	Monmouth Jct	NJ	35,000	1971		35,000	0	38.62
137	Allied Chemical	Cleveland	OH	130,000	1909		38,000	92,000	45.58
138	El Paso Products	El Paso	TX	86,000	1967		16,000	70,000	38.12
	TOTAL			3,039,000			1,756,000	1,283,000	

Average size TPY	94,968
Average size TPD	286
Average year	1946

TABLE N-2. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID IN $0.35/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Steam plants	Smelters	Port Sulphur	Avoidable production cost
10	Allied Chemical	Nitro	WV	135,000	1940	135,000	0	0	38.03
13	Allied Chemical	Front Royal	VA	160,000	1945	107,837	0	52,163	35.94
15	American Cyanamid	Bound Brook	NJ	65,000	1945	0	65,000	0	46.19
16	American Cyanamid	Mobile	AL	26,000	1967	26,000	0	0	41.19
17	American Cyanamid	Joliet	IL	50,000	1937	0	50,000	0	44.08
19	American Cyanamid	Kalamazoo	MI	25,000	1967	0	25,000	0	46.96
20	American Cyanamid	Hamilton	OH	95,000	1967	95,000	0	0	36.76
27	Army Ammunition	Tyner	TN	132,000	1941	132,000	0	0	38.42
28	Army Ammunition	Radford	VA	212,000	1940	78,000	134,000	0	35.95
32	Borden Chemical	Streator	IL	40,000	1951	0	40,000	0	44.70
33	Borden Chemical	Norfolk	VA	80,000	1937	80,000	0	0	38.06
44	Detroit Chemical	Detroit	MI	35,000	1937	35,000	0	0	57.91
46	E. I. Dupont	Richmond	VA	90,000	1946	90,000	0	0	37.27
48	E. I. Dupont	North Bend	OH	175,000	1956	175,000	0	0	42.41
49	E. I. Dupont	Deepwater	NJ	125,000	1937	99,000	26,000	0	36.21
50	E. I. Dupont	Cleveland	OH	200,000	1937	200,000	0	0	43.25
51	E. I. Dupont	Cornwell Hts	PA	75,000	1941	32,426	42,574	0	38.91
52	Eastman Kodak	Rochester	NY	6,000	1930	6,000	0	0	90.47
60	W. R. Grace	Joplin	MO	98,000	1954	91,000	7,000	0	39.68
61	W. R. Grace	Charleston	SC	42,000	1937	0	42,000	0	42.51
68	Kerr-McGee	Cottondale	FL	15,000	1950	15,000	0	0	56.44
70	LJ & M LaPlace	Edison	NJ	75,000	1967	0	57,426	17,574	34.40
72	Minn Mine & Smelt	Copley	OH	65,000	1942	11,000	54,000	0	50.35
75	Monsanto	E.St. Louis	IL	265,000	1937	0	265,000	0	34.04
79	NL Industries	St. Louis	MO	455,000	1958	0	455,000	0	31.12
85	Olin Corporation	Little Rock	AR	105,000	1947	105,000	0	0	44.27
88	Olin Corporation	Pasadena	TX	500,000	1946	0	127,000	373,000	30.30
91	Pennsalt Chemicals	Tulsa	OK	110,000	1937	101,000	9,000	0	40.44
95	Reichhold Chemical	Tuscaloosa	AL	55,000	1957	55,000	0	0	39.15
96	Royster Company	Mulberry	FL	325,000	1967	250,963	0	74,037	35.60
98	Royster Company	Norfolk	VA	20,000	1937	20,000	0	0	51.70
102	Stauffer Chemicals	LeMoyne	AL	250,000	1957	250,000	0	0	35.06
104	Stauffer Chemicals	Fort Worth	TX	120,000	1925	0	83,000	37,000	37.68
107	Swift Chem Co	Calumet Cty	IL	40,000	1942	0	40,000	0	45.66
108	Swift Chem Co	Wilmington	NC	32,000	1944	32,000	0	0	45.25
109	Swift Chem Co	Norfolk	VA	35,000	1946	35,000	0	0	44.28
113	US Industrial	Dubuque	IA	98,000	1940	0	60,000	38,000	38.05
116	USS Agri-Chem	Navassa	NC	70,000	1967	70,000	0	0	38.72
119	Weaver Fertilizer	Norfolk	VA	35,000	1967	35,000	0	0	44.55
120	Acme (Wright) Fertilizer	Acme	NC	48,000	1968	3,209	0	44,791	36.22
126	American Cyanamid	Fortier	LA	50,000	1967	0	50,000	0	40.31
128	Home Guano	Dothan	AL	11,000	1937	11,000	0	0	66.35
130	Columbia Nitrogen	Moultrie	GA	24,000	1947	0	24,000	0	49.51
132	Marion Manufacturing	Indianapolis	IN	56,000	1947	56,000	0	0	44.82
133	E. I. Dupont	Gibbstown	NJ	110,000	1957	110,000	0	0	40.50
135	Cities Service	Monmouth Jct	NJ	35,000	1971	0	35,000	0	38.62
137	Allied Chemical	Cleveland	OH	130,000	1909	81,000	49,000	0	45.58
138	El Paso Products	El Paso	TX	86,000	1967	0	16,000	70,000	38.12
	TOTAL			5,086,000		2,623,435	1,756,000	706,565	

Average TPY	105,958
Average TPD	321
Average Year	1948

TABLE N-3. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID IN $0.50/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Steam Plants	Smelters	Port Sulphur	Avoidable production cost
10	Allied Chemical	Nitro	WV	135,000	1940	135,000	0	0	38.03
11	Allied Chemical	Hopewell	VA	200,000	1965	200,000	0	0	35.50
13	Allied Chemical	Front Royal	VA	160,000	1945	160,000	0	0	35.94
15	American Cyanamid	Bound Brook	NJ	65,000	1945	65,000	0	0	46.19
16	American Cyanamid	Mobile	AL	26,000	1967	26,000	0	0	41.19
17	American Cyanamid	Joliet	IL	50,000	1937	50,000	0	0	44.08
19	American Cyanamid	Kalamazoo	MI	25,000	1967	25,000	0	0	46.96
20	American Cyanamid	Hamilton	OH	95,000	1967	95,000	0	0	36.76
27	Army Ammunition	Tyner	TN	132,000	1941	132,000	0	0	38.42
28	Army Ammunition	Radford	VA	212,000	1940	12,000	200,000	0	35.95
32	Borden Chemical	Streator	IL	40,000	1951	40,000	0	0	44.70
33	Borden Chemical	Norfolk	VA	80,000	1937	80,000	0	0	38.06
40	Cities Service	Augusta	GA	125,000	1967	125,000	0	0	32.51
44	Detroit Chemical	Detroit	MI	35,000	1937	35,000	0	0	57.91
46	E. I. Dupont	Richmond	VA	90,000	1946	90,000	0	0	37.27
48	E. I. Dupont	North Bend	OH	175,000	1956	175,000	0	0	42.41
49	E. I. Dupont	Deepwater	NJ	125,000	1937	99,000	26,000	0	36.21
50	E. I. Dupont	Cleveland	OH	200,000	1937	198,000	2,000	0	43.25
51	E. I. Dupont	Cornwell Hts	PA	75,000	1941	75,000	0	0	38.91
52	Eastman Kodak	Rochester	NY	6,000	1930	6,000	0	0	90.47
53	Essex Chemical	Newark	NJ	180,000	1956	28,265	151,735	0	33.20
56	Gardinier	Tampa	FL	450,000	1937	450,000	0	0	34.17
60	W. R. Grace	Joplin	MO	98,000	1954	91,000	7,000	0	39.68
61	W. R. Grace	Charleston	SC	42,000	1937	42,000	0	0	42.51
62	W. R. Grace	Bartow	FL	320,000	1960	6,431	0	313,569	33.81
68	Kerr-McGee	Cottondale	FL	15,000	1950	15,000	0	0	56.44
70	LJ & M LaPlace	Edison	NJ	75,000	1950	26,735	48,265	0	34.40
72	Minn Mine & Smelt	Copley	OH	65,000	1942	0	65,000	0	50.35
74	Mobil Oil	Depue	IL	420,000	1967	420,000	0	0	31.19
75	Monsanto Co	E. St. Louis	IL	265,000	1937	145,546	119,454	0	34.04
77	Monsanto Co	El Dorado	AR	100,000	1960	100,000	0	0	35.03
79	NL Industries	St. Louis	MO	455,000	1958	176,480	278,520	0	31.12
83	Occidental Ag Chem	Plainview	TX	100,000	1963	95,195	0	4,805	36.84
85	Olin Corporation	N. Little Rk	AR	105,000	1947	92,974	12,026	0	44.27
88	Olin Corporation	Pasadena	TX	500,000	1946	0	498,000	2,000	30.30
91	Pennsalt Chemicals	Tulsa	OK	110,000	1937	101,000	9,000	0	40.44
95	Reichhold Chemical	Tuscaloosa	AL	55,000	1957	55,000	0	0	39.15
96	Royster Company	Mulberry	FL	325,000	1967	325,000	0	0	35.60
98	Royster Company	Norfolk	VA	20,000	1937	20,000	0	0	51.70
102	Stauffer Chemical	LeMoyne	AL	250,000	1957	250,000	0	0	35.06
104	Stauffer Chemical	Fort Worth	TX	120,000	1925	37,000	83,000	0	37.68
107	Swift Chemicals	Calumet Cty	IL	40,000	1942	40,000	0	0	45.66
108	Swift Chemicals	Wilmington	NC	32,000	1944	32,000	0	0	45.25
109	Swift Chemicals	Norfolk	VA	35,000	1946	35,000	0	0	44.28
113	US Industrial	Dubuque	IA	98,000	1940	98,000	0	0	38.05
114	US Industrial	Desoto	KS	105,000	1940	45,000	60,000	0	40.29
116	USS Agri-Chem	Navassa	NC	70,000	1967	70,000	0	0	38.72
119	Weaver Fertilizer	Norfolk	VA	35,000	1967	35,000	0	0	44.55
120	Acme (Wright) Fertilizer Co	Acme	NC	48,000	1968	48,000	0	0	36.22
126	American Cyanamid	Fortier	LA	50,000	1967	50,000	0	0	40.31
128	Home Guano Co	Dothan	AL	11,000	1937	11,000	0	0	66.35
130	Columbia Nitrogen	Moultrie	GA	24,000	1947	24,000	0	0	49.51
131	US Industrial Chem	Tuscola	IL	170,000	1975	170,000	0	0	32.12
132	Marion Manufacturing	Indianapolis	IN	56,000	1947	56,000	0	0	44.82
133	E. I. Dupont	Gibbstown	NJ	110,000	1957	110,000	0	0	40.50
134	E. I. Dupont	Linden	NJ	325,000	1937	46,751	0	278,249	32.78
135	Cities Service Oil	Monmouth Jct	NJ	35,000	1971	35,000	0	0	38.62
136	USS Agri-Chem	Wilmintgon	NC	70,000	1968	70,000	0	0	33.94
137	Allied Chemicals	Cleveland	OH	130,000	1909	94,000	36,000	0	45.58
138	El Paso Products	El Paso	TX	86,000	1967	0	16,000	70,000	38.12
	TOTAL			7,651,000		5,370,377	1,612,000	668,623	

Average TPY 127,516
Average TPD 386
Average Year 1950

TABLE N-4. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID IN $0.70/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Steam plants	Smelters	Port Sulphur	Avoidable production cost
10	Allied Chemical	Nitro	WV	135,000	1940	135,000	0	0	38.03
11	Allied Chemical	Hopewell	VA	200,000	1965	200,000	0	0	35.50
13	Allied Chemical	Front Royal	VA	160,000	1945	59,000	101,000	0	35.94
15	American Cyanamid	Bound Brook	NJ	65,000	194[illegible]	55,000	0	0	46.19
16	American Cyanamid	Mobile	AL	26,000	196[illegible]	26,000	0	0	41.19
17	American Cyanamid	Joliet	IL	50,000	1937	9,000	41,000	0	44.08
18	American Cyanamid	Savannah	GA	216,000	1967	216,000	0	0	29.80
19	American Cyanamid	Kalamazoo	MI	25,000	1967	25,000	0	0	46.96
20	American Cyanamid	Hamilton	OH	95,000	1967	95,000	0	0	36.76
27	Army Ammunitions	Tyner	TN	132,000	1941	132,000	0	0	38.42
28	Army Ammunitions	Radford	VA	212,000	1940	212,000	0	0	35.95
32	Borden Chemical	Streator	IL	40,000	1951	40,000	0	0	44.70
33	Borden Chemical	Norfolk	VA	80,000	1937	80,000	0	0	38.06
40	Cities Service	Augusta	GA	125,000	1967	125,000	0	0	32.51
44	Detroit Chemical	Detroit	MI	35,000	1937	35,000	0	0	57.91
46	E. I. Dupont	Richmond	VA	90,000	1946	90,000	0	0	37.27
48	E. I. Dupont	North Bend	OH	175,000	1956	173,000	2,000	0	42.41
49	E. I. Dupont	Deepwater	NJ	125,000	1937	99,000	26,000	0	36.21
50	E. I. Dupont	Cleveland	OH	200,000	1937	200,000	0	0	43.25
51	E. I. Dupont	Cornwell Hts	PA	75,000	1941	75,000	0	0	38.91
52	Eastman Kodak	Rochester	NY	6,000	1930	6,000	0	0	90.47
53	Essex Chem Co	Newark	NJ	180,000	1956	75,016	104,984	0	33.20
56	Gardinier	Tampa	FL	450,000	1937	450,000	0	0	34.17
60	W. R. Grace	Joplin	MO	98,000	1954	91,000	7,000	0	39.68
61	W. R. Grace	Charleston	SC	42,000	1937	42,000	0	0	42.51
62	W. R. Grace	Bartow	FL	320,000	1960	320,000	0	0	33.81
68	Kerr-McGee	Cottondale	FL	15,000	1950	15,000	0	0	56.44
70	LJ & M LaPlace	Edison	NJ	75,000	1967	56,947	18,053	0	34.40
72	Minn Mine & Smelt	Copley	OH	65,000	1942	65,000	0	0	50.35
74	Mobil Oil	Depue	IL	420,000	1967	420,000	0	0	31.19
75	Monsanto	E. St. Louis	IL	265,000	1937	0	265,000	0	34.04
77	Monsanto	El Dorado	AR	100,000	1960	100,000	0	0	35.03
79	NL Industries	St. Louis	MO	455,000	1958	420,000	35,000	0	31.12
83	Occidental Ag Chem	Plainview	TX	100,000	1963	95,195	0	4,805	36.84
85	Olin Corporation	N.Little Rck	AR	105,000	1947	105,000	0	0	44.27
86	Olin Corporation	Baltimore	MD	350,000	1941	35,037	0	314,963	32.48
88	Olin Corporation	Pasadena	TX	500,000	1946	0	500,000	0	30.30
91	Pennsalt Chemical	Tulsa	OK	110,000	1937	87,000	23,000	0	40.44
95	Reichhold Chemical	Tuscaloosa	AL	55,000	1957	55,000	0	0	39.15
96	Royster Company	Mulberry	FL	325,000	1967	325,000	0	0	35.60
98	Royster Company	Norfolk	VA	20,000	1937	20,000	0	0	51.70
102	Stauffer Chemical	LeMoyne	AL	250,000	1957	250,000	0	0	35.06
104	Stauffer Chemical	Fort Worth	TX	120,000	1925	120,000	0	0	37.68
107	Swift Chem Co	Calumet Cty	IL	40,000	1942	0	40,000	0	45.66
108	Swift Chem Co	Wilmington	NC	32,000	1944	0	32,000	0	45.25
109	Swift Chem Co	Norfolk	VA	35,000	1946	35,000	0	0	44.28
113	US Industrial	Dubuque	IA	98,000	1940	98,000	0	0	38.05
114	US Industrial	Desoto	KS	105,000	1940	45,000	60,000	0	40.25
116	USS Agri Chem	Navassa	NC	70,000	1967	20,000	50,000	0	38.72
119	Weaver Fertilizer	Norfolk	VA	35,000	1967	35,000	0	0	44.55
120	Acme (Wright) Fertilizer Co	Acme	NC	48,000	1968	0	48,000	0	36.22
126	American Cyanamid	Fortier	LA	50,000	1967	50,000	0	0	40.31
128	Home Guano Co	Dothan	AL	11,000	1937	11,000	0	0	66.35
130	Columbia Nitrogen	Moultrie	GA	24,000	1947	24,000	0	0	49.51
131	US Industrial	Tuscola	IL	170,000	1975	170,000	0	0	32.12
132	Marion Manufacturing	Indianapolis	IN	56,000	1947	56,000	0	0	44.82
133	E. I. Dupont	Gibbstown	NJ	110,000	1957	110,000	0	0	40.50
134	E. I. Dupont	Linden	NJ	325,000	1937	0	76,963	248,037	32.78
135	Cities Service	Monmouth Jct	NJ	35,000	1971	35,000	0	0	38.62
136	USS Agri Chem	Wilmington	NC	70,000	1968	0	70,000	0	33.94
137	Allied Chem	Cleveland	OH	130,000	1909	130,000	0	0	45.58
138	El Paso Products	El Paso	TX	86,000	1967	5,523	16,000	64,477	38.12
	TOTAL			8,217,000		6,068,718	1,516,000	632,282	

Average TPY	132,532
Average TPD	401
Average year	1950

TABLE N-5. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID AND FRASCH S IN $0.00/MBTU ACFL MODEL RUN

Number	Acid plant	Smelter	Location	Addition acid demand tons/yr
51	E. I. Dupont DeNemours	Canada-Buffalo		10,000
60	W. R. Grace	Amax Lead Company	Salem (Buick), Mo	91,000
79	N. L. Industries	St. Joe Minerals American Metal (Amax)	Herculaneum, Mo	360,000
88	Olin Corporation	Arizona-Houston		382,000
91	Pennsalt Chemical	Engelhard-National Zinc	Bartlesville, Ok	101,000
104	Stauffer Chemicals	American Smelt (Asarco)	Corpus Christi, Tx	37,000
113	U.S. Industrial Chemical	New Mexico-Chicago		5,000
114	U.S. Industrial Chemical	Climax Molybdenum	Ft. Madison, Ia	45,000
133	E. I. Dupont DeNemours	New Jersey Zinc Co.	Palmerton, Pa	90,000
137	Allied Chem Corporation	Armco Steel Climax Molybdenum	Langeloth, Pa	92,000
138	El Paso Products	Amer Smelt (Asarco)	El Paso, Tx	70,000
			Acid demand balance	1,283,000

TABLE N-6. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID AND FRASCH S IN $0.35/MBTU ACFL MODEL RUN

Number	Acid plant	Smelter	Location	Additional acid demand tons/yr
70	LJ & M	Canada-Buffalo	Canada	17,574
88	Olin Corporation	Arizona; New Mexico-Houston	Arizona; New Mexico	373,000
104	Stauffer Chemical	American Smelt (Asarco)	Corpus Christi, Tx	37,000
113	U.S. Industrial Chemical	Climax Molybdenum	Fort Madison, Ia	38,000
138	El Paso	American Smelt (Asarco)	El Paso, Tx	70,000
			Subtotal	535,574

Number	Company	Steam plant	Number	Additional acid demand tons/yr
13	Allied Chemical	Paradise	6 4770003000	52,163
96	Royster Company	Big Bend	5 4740000300	74,037
120	Acme (Wright) Fert	Belews Creek	1 1395000250	44,791
			Subtotal	170,991
			Acid demand balance	706,565

TABLE N-7. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID AND FRASCH S IN $0.50/MBTU ACFL MODEL RUN

Number	Acid plant	Smelter	Location	Additional acid demand tons/yr
88	Olin Corporation	Arizona; New Mexico-Houston	Arizona;New Mexico	2,000
138	El Paso Products	Asarco	El Paso	70,000
			Subtotal	72,000

Number	Company	Steam plant	Number	Additional acid demand tons/yr
62	W. R. Grace	Crystal River	14 1655000300	313,569
		Wansley	15 1790002550	
83	Occidental Ag. Chem	Harrington	29 4530000850	4,805
134	E. I. Dupont DeNemours	Roseton	3 7000000550	278,249
			Subtotal	596,623
			Acid demand balance	668,623

TABLE N-8. ACID PLANTS BUYING ABATEMENT BYPRODUCT ACID AND FRASCH S IN $0.70/MBTU ACFL MODEL RUN

Number	Company Buying	Smelter	Smelter Location	Additional acid demand tons/yr
134	E. I. Dupont DeNemours	Canada-Buffalo	Canada	248,037
138	El Paso Products	Asarco	El Paso	64,477
			Subtotal	312,514

Number	Company Buying	Steam plant	Number	Additional acid demand tons/yr
83	Occidental Ag Chem	Harrington	41 4530000850	4,805
86	Olin Corporation	Homer City	34 3795000350	314,963
			Subtotal	319,768
			Acid demand balance	632,282

TABLE N-9. FIFTY-EIGHT ACID PLANTS BUYING FRASCH S ONLY IN $0.00/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Avoidable production cost
1	Agrico Chem-Williams	Pierce	FL	1,200,000	1975	25.64
2	Agrico Chem-Williams	Donaldsville	LA	1,200,000	1975	28.45
7	Allied Chemical	Geismar	LA	500,000	1968	27.26
10	Allied Chemical	Nitro	WV	135,000	1940	38.03
11	Allied Chemical	Hopewell	VA	200,000	1965	35.50
13	Allied Chemical	Front Royal	VA	160,000	1945	35.94
18	American Cyanamid	Savannah	GA	216,000	1967	29.80
20	American Cyanamid	Hamilton	OH	95,000	1967	36.76
21	American Cyanamid	Linden	NJ	245,000	1970	29.82
28	Army Ammunition Plt	Radford	VA	212,000	1940	35.95
31	Beker Industries	Taft	LA	525,000	1965	27.53
33	Borden Chemical	Norfolk	VA	80,000	1937	38.06
34	Borden Chemical	Port Manatee	FL	490,000	1967	27.60
36	CF Industries	Plant City	FL	1,550,000	1967	25.85
37	CF Industries	Bonnie	FL	1,190,000	1967	26.35
38	CF Industries	Bonnie	FL	660,000	1976	26.21
40	Cities Service	Augusta	GA	125,000	1967	32.51
43	Delta Chemical	Searsport	ME	75,000	1942	39.36
46	E. I. Dupont	Richmond	VA	90,000	1946	37.27
48	E. I. Dupont	North Bend	OH	175,000	1956	42.41
49	E. I. Dupont	Deepwater	NJ	125,000	1937	36.21
50	E. I. Dupont	Cleveland	OH	200,000	1937	43.25
53	Essex Chemical	Newark	NJ	180,000	1956	33.20
54	Farmland Industries	Pierce	FL	1,226,000	1965	26.50
55	Freeport Minerals	Uncle Sam	LA	2,160,000	1969	25.23
56	Gardinier	Tampa	FL	450,000	1937	34.17
57	Gardinier	Tampa	FL	1,050,000	1974	28.26
58	Gardinier	Tampa	FL	883,000	1977	31.72
61	W. R. Grace	Charleston	SC	42,000	1937	42.41
62	W. R. Grace	Bartow	FL	320,000	1960	33.81
63	W. R. Grace	Bartow	FL	480,000	1960	32.49
66	International Miner	Bonnie	FL	1,980,000	1975	25.19
67	W. R. Grace	Bartow	FL	1,280,000	1977	30.96
70	LJ & M LaPlace	Edison	NJ	75,000	1967	34.40
73	Miss Chem Corporation	Pascagoula	MS	1,220,000	1958	27.27
74	Mobil Oil	Dupue	IL	420,000	1967	31.19
76	Monsanto	Everett	MA	120,000	1969	32.30
77	Monsanto	El Dorado	AR	100,000	1960	35.03
83	Occidental Ag Chem	Plainview	TX	100,000	1963	36.84
84	Occidental Ag Chem	White Springs	FL	1,650,000	1967	26.87
86	Olin Corporation	Baltimore	MD	350,000	1941	32.48
96	Royster Company	Mulberry	FL	325,000	1976	35.60
102	Stauffer Chemicals	LeMoyne	AL	250,000	1957	35.06
109	Swift Chemicals	Norfolk	VA	35,000	1946	44.28
110	Swift Chemicals	Agricola	FL	220,000	1976	32.73
111	Texasgulf Inc.	Lee Creek	NC	1,357,000	1966	30.30
115	USS Agri Chem	Bartow	FL	280,000	1964	29.12
116	USS Agri Chem	Navassa	NC	70,000	1976	38.72
117	USS Agri Chem	Ft. Meade	FL	540,000	1963	27.92
119	Weaver Fertilizer	Norfolk	VA	35,000	1976	44.55
120	Acme (Wright) Fert Co	Acme	NC	48,000	1968	36.22
127	NL Industries	Sayreville	NJ	560,000	1937	31.41
129	Englehardt McConser	Nichols	FL	400,000	1945	30.88
131	US Industrial Chem	Tuscola	IL	170,000	1975	32.12
134	E. I. Dupont	Linden	NJ	325,000	1937	32.78
136	USS Agri Chem	Wilmington	NC	70,000	1968	33.94
142	American Cyanamid	Fortier	LA	530,000	1978	29.75
176	Texasgulf Inc.	Lee Creek	NC	449,000	1976	31.76
TOTAL				29,198,000		

Average TPY 503,414
Average TPD 1,525

Average year 1961

TABLE N-10. FORTY-TWO ACID PLANTS BUYING FRASCH S ONLY IN $0.35/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Avoidable production cost
1	Agrico Chem-Williams	Pierce	FL	1,200,000	1975	25.64
2	Agrico Chem-Williams	Donaldsville	LA	1,200,000	1975	28.45
7	Allied Chemical	Geismar	LA	500,000	1968	27.26
11	Allied Chemical	Hopewell	VA	200,000	1965	35.30
18	American Cyanamid	Savannah	GA	216,000	1967	29.80
21	American Cyanamid	Linden	NJ	245,000	1970	29.82
31	Beker Industries	Taft	LA	525,000	1965	27.53
34	Borden Chemical	Port Manatee	FL	490,000	1967	27.60
36	CF Industries	Plant City	FL	1,550,000	1967	25.85
37	CF Industries	Bonnie	FL	1,190,000	1967	26.35
38	CF Industries	Bonnie	FL	660,000	1976	26.21
40	Cities Service	Augusta	GA	125,000	1967	32.51
43	Delta Chemicals	Searsport	ME	75,000	1942	39.36
53	Essex Chemicals	Newark	NJ	180,000	1956	33.20
54	Farmland Industries	Pierce	FL	1,226,000	1965	26.50
55	Freeport Minerals	Uncle Sam	LA	2,160,000	1969	25.23
56	Gardinier	Tampa	FL	450,000	1937	34.17
57	Gardinier	Tampa	FL	1,050,000	1974	28.26
58	Gardinier	Tampa	FL	883,000	1977	31.72
62	W. R Grace	Bartow	FL	320,000	1960	33.81
63	W. R. Grace	Bartow	FL	480,000	1960	32.49
66	International Miner	Bonnie	FL	1,980,000	1975	25.19
67	W. R. Grace	Bartow	FL	1,280,000	1977	30.96
73	Miss Chem Corporation	Pascagoula	MS	1,220,000	1958	27.27
74	Mobil Oil	Dupue	IL	420,000	1967	31.19
76	Monsanto	Everett	MA	120,000	1969	32.30
77	Monsanto	El Dorado	AR	100,000	1960	35.03
83	Occidental Ag Chem	Plainview	TX	100,000	1963	36.84
84	Occidental Ag Chem	White Springs	FL	1,650,000	1967	26.87
86	Olin Corporation	Baltimore	MD	350,000	1941	32.48
110	Swift Chemicals	Agricola	FL	220,000	1976	32.73
111	Texasgulf Inc.	Lee Creek	NC	1,357,000	1966	30.30
114	US Industrial Chem	Desoto	KS	105,000	1940	
115	USS Agri Chem	Bartow	FL	280,000	1964	29.12
117	USS Agri Chem	Ft. Meade	FL	540,000	1963	27.92
127	NL Industries	Sayreville	NJ	560,000	1937	31.41
129	Englehardt McConser	Nichols	FL	400,000	1945	30.88
131	US Industrial Chem	Tuscola	IL	170,000	1975	32.12
134	E. I. Dupont	Linden	NJ	325,000	1937	32.78
136	USS Agri Chem	Wilmington	NC	70,000	1968	33.94
142	American Cynamid	Fortier	LA	530,000	1978	29.75
176	Texasgulf Inc.	Lee Creek	NC	449,000	1976	31.76
	TOTAL			27,151,000		

Average TPY 646,452
Average TPD 1,958

Average year 1964

TABLE N-11. THIRTY ACID PLANTS BUYING FRASCH S ONLY IN $0.50/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Avoidable production cost
1	Agrico Chem Williams	Pierce	FL	1,200,000	1975	25.64
2	Agrico Chem Williams	Donaldsville	LA	1,200,000	1975	28.45
7	Allied Chemical	Geismar	LA	500,000	1968	27.26
18	American Cyanamid	Savannah	GA	216,000	1967	29.80
21	American Cyanamid	Linden	NJ	245,000	1970	29.82
31	Beker Industries	Taft	LA	525,000	1965	27.53
34	Borden Chemicals	Port Manatee	FL	490,000	1967	27.60
36	CF Industries	Plant City	FL	1,550,000	1967	25.85
37	CF Industries	Bonnie	FL	1,190,000	1967	26.35
38	CF Industries	Bonnie	FL	660,000	1976	26.21
43	Delta Chemicals	Searsport	ME	75,000	1942	39.36
54	Farmland Industries	Pierce	FL	1,226,000	1965	26.50
55	Freeport Minerals	Uncle Sam	LA	2,160,000	1969	25.23
57	Gardinier	Tampa	FL	1,050,000	1974	34.17
58	Gardinier	Tampa	FL	883,000	1977	31.72
63	W. R. Grace	Bartow	FL	480,000	1960	32.49
66	International Miner	Bonnie	FL	1,980,000	1975	25.19
67	W. R. Grace	Bartow	FL	1,280,000	1977	30.96
73	Miss Chem Corporation	Pascagoula	MS	1,220,000	1958	27.27
76	Monsanto	Everett	MA	120,000	1969	32.30
84	Occidental Ag Chem	White Springs	FL	1,650,000	1967	26.87
86	Olin Corporation	Baltimore	MD	350,000	1941	32.48
110	Swift Chemicals	Agricola	FL	220,000	1976	32.73
111	Texasgulf Inc.	Lee Creek	NC	1,357,000	1966	30.30
115	USS Agri Chem	Bartow	FL	280,000	1964	29.12
117	USS Agri Chem	Ft. Meade	FL	540,000	1963	27.92
127	NL Industries	Sayreville	NJ	560,000	1937	31.41
129	Englehardt McConser	Nichols	FL	400,000	1945	30.88
142	American Cyanamid	Fortier	LA	530,000	1978	29.75
176	Texasgulf Inc.	Lee Creek	NC	449,000	1976	31.76
	TOTAL			24,586,000		

Average TPY	819,533
Average TPD	2,483
Average year	1966

TABLE N-12. TWENTY-EIGHT ACID PLANTS BUYING FRASCH S ONLY

IN $0.70/MBTU ACFL MODEL RUN

#	Company	Location		Capacity	Year	Avoidable production cost
1	Agri Chem Williams	Pierce	FL	1,200,000	1975	25.64
2	Agri Chem Williams	Donaldsville	LA	1,200,000	1975	28.45
7	Allied Chemical	Geismar	LA	500,000	1968	27.26
21	American Cyanamid	Linden	NJ	245,000	1970	29.82
31	Beker Industries	Taft	LA	525,000	1965	27.53
34	Borden Chemicals	Port Manatee	FL	490,000	1967	27.60
36	CF Industries	Plant City	FL	1,550,000	1967	25.85
37	CF Industries	Bonnie	FL	1,190,000	1967	26.35
38	CF Industries	Bonnie	FL	660,000	1976	26.21
43	Delta Chemicals	Searsport	ME	75,000	1942	39.36
54	Farmland Industries	Pierce	FL	1,226,000	1965	26.50
55	Freeport Minerals	Uncle Sam	LA	2,160,000	1969	25.23
57	Gardinier	Tampa	FL	1,050,000	1974	28.26
58	Gardinier	Tampa	FL	883,000	1977	31.72
63	W. R. Grace	Bartow	FL	480,000	1960	32.49
66	International Miner	Bonnie	FL	1,980,000	1975	25.19
67	W. R. Grace	Bartow	FL	1,280,000	1977	30.96
73	Miss Chem Corporation	Pascagoula	MS	1,220,000	1958	27.27
76	Monsanto	Everett	MA	120,000	1969	35.03
84	Occidental Ag Chem	White Springs	FL	1,650,000	1967	26.87
110	Swift Chemicals	Agricola	FL	220,000	1976	32.73
111	Texasgulf Inc.	Lee Creek	NC	1,357,000	1966	30.30
115	USS Agri Chem	Bartow	FL	280,000	1964	29.12
117	USS Agri Chem	Ft. Meade	FL	540,000	1963	27.92
127	NL Industries	Sayreville	NJ	560,000	1937	31.41
129	Englehardt McConser	Nichols	FL	400,000	1945	30.88
142	American Cyanamid	Fortier	LA	530,000	1978	29.75
176	Texasgulf Inc	Lee Creek	NC	449,000	1976	31.76
	TOTAL			24,020,000		

Average TPY	857,857
Average TPD	2,599
Average year	1967

TABLE N-13. SET I - $0.00/MBTU ACFL MODEL RUN

IA - Acid plants partially dependent on abatement byproduct acid supplies

#	Name	Location	Demand	Port Sulphur	Abatement
51	E. I. Dupont	Cornwell Hts. PA	75	10	65
60	W. R. Grace	Joplin MO	98	91	7
79	NL Industries	St. Louis MO	455	360	95
88	Olin Corporation	Pasadena TX	500	382	118
91	Pennsalt Chem	Tulsa OK	110	101	9
104	Stauffer Chem	Ft. Worth TX	120	37	83
113	US Industrial Chem	Dubuque IA	98	5	93
114	US Industrial Chem	Desoto KS	105	45	60
133	E. I. Dupont	Gibbstown NJ	110	90	20
137	Allied Chem Corp	Cleveland OH	130	92	38
138	El Paso Products	El Paso TX	86	70	16
	TOTALS		1,887	1,283	604

IB - Supply points not satisfying total demand requirements

SMELTERS

Area	Smelter	Location	Potential demand	Amount selling	Demand balance	Acid plant No.
Canada		Canada	75	65	10	51
Eastern	Amax Lead Co.	Salem(Buick) MO	98	7	91	60
Eastern	St. Joe Minerals	Herculaneum MO	455	14	0	79
Eastern	Amer Metal (Amax)	Monsanto IL	455	12	360	79
Eastern	Amer Metal (Amax)	Monsanto IL	455	23		79
West		Montana	455	46	0	79
West		Arizona	500	118	382	88
Eastern	Englehard Nat'l Zinc	Bartlesville OK	110	9	101	91
Eastern	Amer Smelt (Asarco)	Corpus Crsti TX	120	7	37	104
Eastern	Amer Smelt (Asarco)	Corpus Crsti TX	120	76		104
West		New Mexico	98	93	5	113
Eastern	Climax Molybdenum	Ft Madison IA	105	60	45	114
Eastern	New Jersey Zinc Co		110	20	90	133
Eastern	Armco Steel		130	2	92	137
Eastern	Climax Molybdenum	Langeloth PA	130	36	0	137
Eastern	Amer Smelt (Asarco)	El Paso TX	86	16	70	138
TOTALS			1,887	604	1,283	

TABLE N-14. SET II - $0.35/MBTU ACFL MODEL RUN

IIA - Acid plants partly dependent on abatement byproduct acid supplies

#	Name	Location		Demand	Port Sulphur	Abatement
13	Allied Chem Corp	Front Royal	VA	160	52.163	107.837
70	LJ & M LaPlace Cde	Edison	NJ	75	17.574	57.426
88	Olin Corporation	Pasadena	TX	500	373.000	127.000
96	Royster Co.	Mulberry	FL	325	74.037	250.963
104	Stauffer Chem Co.	Ft. Worth	TX	120	37.000	83.000
113	US Industrial Chem	Dubuque	IA	98	38.000	60.000
120	Acme (Wright) Fert	Acme	NC	48	44.791	3.209
138	El Paso Products	El Paso	TX	86	70.000	16.000
	TOTALS			1,412	706.565	705.435

IIB - Supply points not satisfying total demand requirements

SMELTERS

Area	Smelter	Location		Potential demand	Amount selling	Demand balance	Acid plant No
Canada		Canada		75	57.426	17.574	70
Western		Arizona		500	118.000	373.000	88
Western		New Mexico		500	9.000	0.000	88
Eastern	Amer Smelt (Asarco)	Corpus Christi	TX	120	7.000	37.000	104
Eastern	Amer Smelt (Asarco)	Corpus Christi	TX	120	76.000	0.000	104
Eastern	Climax Molybdenum	Ft Madison	IA	98	60.000	38.000	113
Eastern	Amer Smelt (Asarco)	El Paso	TX	86	16.000	70.000	138
TOTALS				879	343.426	535.574	

POWER PLANTS

Number	Location	Potential demand	Amount selling	Demand balance	Acid plant No
6 4770003000	Kentucky	160	107.837	52.163	13
5 4740000300	Florida	325	250.963	74.037	96
1 1395000250	North Carolina	48	3.209	44.791	120
TOTALS		533	362.009	170.991	

TABLE N-15. SET III - $0.50/MBTU ACFL MODEL RUN

IIIA - Acid plants partly dependent on abatement byproduct acid supplies

#	Name	Location		Capacity	Port Sulphur	Abatement
62	W. R. Grace & Co.	Bartow	FL	320	313.569	6.431
83	Occidental Ag Chem	Plainview	TX	100	4.805	95.195
88	Olin Corporation	Pasadena	TX	500	2.000	498.000
134	E. I. Dupont	Linden	NJ	325	278.249	46.751
138	El Paso Products	El Paso	TX	86	70.000	16.000
	TOTALS			1,331	668.623	662.377

IIIB - Supply points not satisfying total demand requirements

SMELTERS

Area	Smelter	Location		Potential demand	Amount selling	Demand balance	Acid plant No.
Western		Arizona		500	118	2.	88
Western		New Mexico		500	380	0.	88
Eastern	Amer Smelt (Asarco)	El Paso	TX	86	16	70.	138
TOTALS				586	514	72	

POWER PLANTS

Number	Location	Potential demand	Amount selling	Demand balance	Acid plant No.
14 1655000300	Florida	320	2.101	0.	62
15 1790002550	Georgia	320	4.330	313.569	62
29 4530000850	Texas	100	95.195	4.805	83
3 0700000550	New York	325	46.751	278.249	134
TOTALS		745	148.377	596.623	

TABLE N-16. SET IV - $0.70/MBTU ACFL MODEL RUN

IVA - Acid plants partly dependent on abatement byproduct acid supplies

#	Name	Location		Capacity	Port Sulphur	Abatement
83	Occidental Ag Chem	Plainview	TX	100	4.805	95.195
86	Olin Corporation	Baltimore	MD	350	314.963	35.037
134	E. I. Dupont	Linden	NJ	325	248.037	76.963
138	El Paso Products	El Paso	TX	86	64.477	21.523
	TOTALS			861	632.282	228.718

IVB - Supply points not satisfying total demand requirements

SMELTERS

Area	Smelter	Location	Potential demand	Amount selling	Demand balance	Acid plant No.
Canada		Canada	325	76.963	248.037	134
Eastern	Amer Smelt (Asarco)	El Paso TX	86	16.000	64.477	138
			411	92.963	312.514	

POWER PLANTS

Number	Location	Potential demand	Amount selling	Demand balance	Acid plant No.
41 4530000850	Texas	100	95.195	4.805	83
34 3795000350	Pennsylvania	350	35.037	314.963	86
7 1000000050	Texas	(86)	5.523	0.000	138
TOTALS		450	135.755	319.768	

APPENDIX O

SIZE AND OWNERSHIP OF S-BURNING ACID PLANTS

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O-2 S-Burning Acid Plant Capacity by Firm (i978) 224

TABLE O-1. S-BURNING ACID PLANTS ORDERED BY SIZE OF PLANT (1978)

No.	Company	Location		Yr con-structed	Capacity, annual tons	Capacity replaced by abatement acid
55	Freeport Minerals	Uncle Sam	LA	1969	2,160,000	0
66	International Miner	Bonnie	FL	1975	1,980,000	0
84	Occidental Ag Chem	White Springs	FL	1967	1,650,000	0
36	C. F. Industries	Bonnie	FL	1967	1,550,000	0
111	Texasgulf Inc.	Lee Creek	NC	1966	1,357,000	0
67	W. R. Grace	Bartow	FL	1977	1,280,000	0
54	Farmland Industries	Pierce	FL	1965	1,226,000	0
73	Miss. Chem Corp	Pascagoula	MS	1958	1,220,000	0
1	Agri Chem Williams	Pierce	FL	1975	1,200,000	0
2	Agri Chem Williams	Donaldsville	LA	1975	1,200,000	0
37	C. F. Industries	Bonnie	FL	1967	1,190,000	0
57	Gardinier	Tampa	FL	1974	1,050,000	0
58	Gardinier	Tampa	FL	1977	883,000	0
38	C. F. Industries	Bonnie	FL	1976	660,000	0
127	N. L. Industries	Sayreville	NJ	1937	560,000	0
117	USS Agri Chem	Ft. Meade	FL	1963	540,000	0
142	American Cyanamid	Fortier	LA	1978	530,000	0
31	Beker Industries	Taft	LA	1965	525,000	0
7	Allied Chemical	Geismar	LA	1968	500,000	0
88	Olin Corp	Pasadena	TX	1946	500,000	500,000
34	Borden Chemicals	Port Manatee	FL	1967	490,000	0
63	W. R. Grace	Bartow	FL	1960	480,000	0
79	N. L. Industries	St. Louis	MO	1958	455,000	455,000
56	Gardinier	Tampa	FL	1937	450,000	450,000
176	Texasgulf Inc.	Lee Creek	NC	1976	449,000	0
74	Mobil Oil	Depue	IL	1967	420,000	420,000
129	Englehardt McConserv	Nichols	FL	1945	400,000	0
86	Olin Corporation	Baltimore	MD	1941	350,000	35,037
96	Royster Company	Mulberry	FL	1967	325,000	325,000
134	E. I. Dupont	Linden	NJ	1937	325,000	76,963
62	W. R. Grace	Bartow	FL	1960	320,000	320,000
115	USS Agri Chem	Bartow	FL	1964	280,000	0
75	Monsanto	E. St. Louis	IL	1937	265,000	265,000
102	Stauffer Chemical	LeMoyne	AL	1957	250,000	250,000
21	American Cyanamid	Linden	NJ	1970	245,000	0
110	Swift Chemicals	Agricola	FL	1976	220,000	0
18	American Cyanamid	Savannah	GA	1967	216,000	216,000
28	Army Ammunitions	Radford	VA	1940	212,000	212,000
11	Allied Chemical	Hopewell	VA	1965	200,000	200,000
50	E. I. Dupont	Cleveland	OH	1937	200,000	200,000
53	Essex Chem Co	Newark	NJ	1956	180,000	180,000
48	E. I. Dupont	North Bend	OH	1956	175,000	175,000
131	U.S. Industrial	Tuscola	IL	1975	170,000	170,000
13	Allied Chemical	Front Royal	VA	1945	160,000	160,000
10	Allied Chemical	Nitro	WV	1940	135,000	135,000
27	Army Ammunitions	Tyner	TN	1941	132,000	132,000
137	Allied Chemical	Cleveland	OH	1909	130,000	130,000
40	Cities Service	Augusta	GA	1967	125,000	125,000
49	E. I. Dupont	Deepwater	NJ	1937	125,000	125,000
76	Monsanto	Everett	MA	1969	120,000	0
104	Stauffer Chemical	Fort Worth	TX	1925	120,000	120,000
91	Pennsalt Chemical	Tulsa	OK	1937	110,000	110,000
133	E. I. Dupont	Gibbstown	NJ	1957	110,000	110,000
85	Olin Corporation	N. Little Rock	AR	1947	105,000	105,000
114	U. S. Industrial	Desoto	KS	1940	105,000	105,000
77	Monsanto	El Dorado	AR	1960	100,000	100,000
83	Occidental Ag Chem	Plainview	TX	1963	100,000	95,195
60	W. R. Grace	Joplin	MO	1954	98,000	98,000
113	U. S. Industrial	Dubuque	IA	1940	98,000	98,000
20	American Cyanamid	Hamilton	OH	1967	95,000	95,000
46	E. I. Dupont	Richmond	VA	1947	90,000	90,000
138	El Paso Products	El Paso	TX	1967	86,000	21,523
33	Borden Chemical	Norfolk	VA	1937	80,000	80,000
43	Delta Chemicals	Searsport	ME	1942	75,000	0
51	E. I. Dupont	Cornwell Hgts.	PA	1941	75,000	75,000
70	LJ & M LaPlace	Edison	NJ	1967	75,000	75,000
136	USS Agri Chem	Wilmington	NC	1968	70,000	70,000

(continued)

TABLE 0-1 (continued)

No.	Company	Location		Year con-structed	Capacity, annual tons	Capacity replaced by abatement acid
116	USS Agri Chem	Navassa	NC	1967	70,000	70,000
15	American Cyanamid	Bound Brook	NJ	1945	65,000	65,000
72	Minn. Mine & Smelt	Copley	OH	1942	65,000	65,000
132	Marion Manufacturing	Indianapolis	IN	1947	56,000	56,000
95	Reichold Chemical	Tuscaloosa	AL	1957	55,000	55,000
17	American Cyanamid	Joliet	IL	1937	50,000	50,000
126	American Cyanamid	Fortier	LA	1967	50,000	50,000
120	Acme (Wright) Fert Co	Acme	NC	1968	48,000	48,000
61	W. R. Grace	Charleston	SC	1937	42,000	42,000
32	Borden Chemical	Streator	IL	1951	40,000	40,000
107	Swift Chem Company	Calumet City	IL	1942	40,000	40,000
44	Detroit Chemical	Detroit	MI	1937	35,000	35,000
109	Swift Chem Company	Norfolk	VA	1946	35,000	35,000
119	Weaver Fertilizer	Norfolk	VA	1967	35,000	35,000
135	Cities Service	Monmouth Jct	NJ	1971	35,000	35,000
108	Swift Chem Company	Wilmington	NC	1944	32,000	32,000
16	American Cyanamid	Mobile	AL	1967	26,000	26,000
19	American Cyanamid	Kalamazoo	MI	1967	25,000	25,000
130	Columbia Nitrogen	Moultrie	GA	1947	24,000	24,000
98	Royster Company	Norfolk	VA	1937	20,000	20,000
68	Kerr-McGee	Cottondale	FL	1950	15,000	15,000
128	Home Guano Company	Dothan	AL	1937	11,000	11,000
52	Eastman Kodak	Rochester	NY	1930	6,000	6,000
	Total				32,237,000	7,584,716

TABLE O-2. S-BURNING ACID PLANT CAPACITY BY FIRM (1978)

Name	Capacity [tons/yr]	Number of plants	Buying abatement acid at $0.70/MBtu ACFL	
C. F. Industries Inc.	3,400,000	3	0	
Agrico Chem	2,400,000	2	0	Top 5 companies 14 of 90 plants 12,563,000 tons 38.97%
Gardinier	2,383,000	3	1	
W. R. Grace	2,220,000	5	3	
Freeport Mineral	2,160,000	1	0	
International Miner	1,980,000	1	0	
Texasgulf Inc.	1,806,000	2	0	Top 10 companies 29 of 90 plants 20,627,000 tons 63.99%
Occidental Ag	1,750,000	2	1	
American Cyanamid	1,302,000	9	7	
Farmland Industries	1,226,000	1	0	
Miss. Chem Corp	1,220,000	1	0	
Allied Chem Corp	1,125,000	5	4	Top 15 companies 48 of 90 plants 26,047,000 tons 80.79%
E. I. Dupont DeNemours	1,100,000	7	7	
N. L. Industries	1,015,000	2	1	
USS Agri-Chem	960,000	4	2	
Olin Corp	955,000	3	3	
Borden Chemical	610,000	3	2	Top 20 companies 59 of 90 plants 29,042,000 tons 90.09%
Beker Industries	525,000	1	0	
Monsanto Company	485,000	3	2	
Mobil Oil	420,000	1	1	
Englehardt McConser	400,000	1	0	
U.S. Industrial Chem	373,000	3	3	
Stauffer Chem	370,000	2	2	
Royster Company	345,000	2	2	
Army Ammunition Plant	344,000	2	2	
Swift Chem Co.	327,000	4	3	
Essex Chemical Co.	180,000	1	1	
Cities Service Oil	160,000	2	2	
Pennsalt Chemicals	110,000	1	1	
El Paso Chem	86,000	1	1	
Delta Chemical	75,000	1	0	
LJ & M LaPlace Cde	75,000	1	1	
Minn. Mining & Smelting	65,000	1	1	
Marion Manufacturing	56,000	1	1	
Reichold Chemicals	55,000	1	1	
Acme Fertilizer Company	48,000	1	1	
Detroit Chemical	35,000	1	1	
Weaver Fertilizer	35,000	1	1	
Columbia Nitrogen	24,000	1	1	
Kerr-McGee	15,000	1	1	
Home Guano Co.	11,000	1	1	
Eastman Kodak	6,000	1	1	
Total capacity	32,237,000			

APPENDIX P

ACID PLANTS OUT OF COMPLIANCE, RETROFIT COST, AND CANDIDATES FOR PURCHASE OF BYPRODUCT ACID

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TABLE P-1. ACID PLANTS OUT OF COMPLIANCE, RETROFIT COST, AND

CANDIDATES FOR PURCHASE OF BYPRODUCT ACID

No.	Company	Location		Avoidable production cost, $/ton	Retrofit cost, $/ton	Purchase from smelters only	Purchase from power plants when ACFL is		
							$0.35/MBtu	$0.50/MBtu	$0.70/MBtu
2	Agrico Chem-Williams	Donaldsville	LA	28.45	2.80				
11	Allied Chemical	Hopewell	VA	35.50	4.69			X	X
15	American Cyanamid	Bound Brook	NJ	46.19	6.49	X	X	X	X
44	Detroit Chemicals	Detroit	MI	57.91	7.76	X	X	X	X
48	E. I. Dupont	North Bend	OH	42.41	4.88		X	X	X
50	E. I. Dupont	Cleveland	OH	43.25	4.69		X	X	X
56	Gardinier	Tampa	FL	34.17	3.71			X	X
57	Gardinier	Tampa	FL	28.56	2.91				
58	Gardinier	Tampa	FL	31.72	3.06				
62	W. R. Grace	Bartow	FL	33.81	4.10			X[a]	X
63	W. R. Grace	Bartow	FL	32.49	3.65				
67	W. R. Grace	Bartow	FL	30.96	2.75				
72	Minn Mine & Smelting	Copley	OH	50.35	6.49	X	X	X	X
85	Olin Corporation	N. Little Rock	AR	44.27	5.65	X	X	X	X
96	Royster Company	Mulberry	FL	35.60	4.08		X[a]	X	X
102	Stauffer Chemicals	LeMoyne	AL	35.06	4.40		X	X	X
111	Texasgulf Inc.	Lee Creek	NC	30.30	2.70				
133	E. I. Dupont	Gibbstown	NJ	40.50	5.58	X[a]	X	X	X
137	Allied Chemicals	Cleveland	OH	45.58	5.32	X[a]	X	X	X
176	Texasgulf Inc.	Lee Creek	NC	31.76	3.72				

a. Buying from Port Sulphur in addition to byproduct acid.

APPENDIX Q

POWER PLANTS AND ACID PLANTS AFFECTED BY A REDUCTION OF $20/TON IN S PRICE

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TABLE Q-1. EFFECT OF S PRICE CHANGE AT $0.35/MBTU ACFL FOR POWER PLANTS, SMELTERS, AND ACID PLANTS

Two power plants affected by S price change at $0.35/MBtu ACFL

1400000600	Pennsylvania	Total tons	80,409	tons affected	57,794
4770003000	Kentucky	Total tons	628,358	tons affected	188,517
					246,311

Four smelters affected by S price change at $0.35/MBtu ACFL

New Mexico	Houston	Total tons	9,000	tons affected	9,000
New Mexico	St. Louis	Total tons	166,000	tons affected	166,000
Arizona	Houston	Total tons	118,000	tons affected	118,000
Montana	St. Louis	Total tons	144,000	tons affected	144,000
					437,000
					246,311
					683,311

Six acid plants affected by S price change at $0.35/MBtu ACFL

13	Allied Chemical Corp	Front Royal, Virginia			29.83
4770003000	Kentucky	107,837	tons	@	31.73
33	Borden Chemical	Norfolk, Virginia			31.95
4770003000	Kentucky	80,000	tons	@	32.37
48	E. I. Dupont	North Bend, Ohio			36.30
1400000600	Pennsylvania	57,794	tons	@	36.33
60	W. R. Grace	Joplin, Missouri			33.57
4770003000	Kentucky	680	tons	@	34.13
79	N L Industries, Inc.	St. Louis, Missouri			25.01
	New Mexico - St. Louis	166,000	tons	@	28.16
	Montana - St. Louis	144,000	tons	@	28.79
88	Olin Corporation	Pasadena, Texas			24.19
	Arizona - Houston	118,000	tons	@	27.56
	New Mexico - Houston	9,000	tons	@	27.56
		683,311			

TABLE Q-2. EFFECT OF S PRICE CHANGE AT $0.50/MBTU ACFL FOR POWER PLANTS, SMELTERS, AND ACID PLANTS

Six power plants affected by S price change at $0.50/MBtu ACFL

1115001100	Illinois	Total tons	126,788	tons affected	12,054
1655000300	Florida	Total tons	192,742	tons affected	2,101
3455000400	Indiana	Total tons	132,291	tons affected	42,291
4770003000	Kentucky	Total tons	628,358	tons affected	528,297
4770003200	Kentucky	Total tons	288,947	tons affected	44,830
5540000250	Missouri	Total tons	108,149	tons affected	10,149
					639,722

Two smelters affected by S price change at $0.50/MBtu ACFL

Arizona	Houston	Total tons	118,000	tons affected	118,000
New Mexico	Houston	Total tons	380,000	tons affected	380,000
					498,000
					639,722
					1,137,722

Ten acid plants affected by S price change at $0.50/MBtu ACFL

11	Allied Chemical Corp.	Hopewell, Virginia			29.39
4770003000	Kentucky	156,544	tons	@	31.73
33	Borden Chemical Corp	Norfolk, Virginia			31.95
4770003000	Kentucky	80,000	tons	@	32.37
46	E. I. Dupont	Richmond, Virginia			31.16
4770003000	Kentucky	90,000	tons	@	31.73
60	W. R. Grace	Joplin, Missouri			33.57
4770003000	Kentucky	22,394	tons	@	34.13
62	W. R. Grace	Bartow, Florida			27.70
1655000300	Florida	2,101	tons	@	28.55
74	Mobile Oil	Depue, Illinois			25.08
1115001100	Illinois	12,054	tons	@	27.59
3455000400	Indiana	42,291	tons	@	25.36
5540000250	Missouri	10,149	tons	@	27.56
88	Olin Corporation	Pasadena, Texas			24.19
Arizona	Houston	118,000	tons	@	27.56
New Mexico	Houston	380,000	tons	@	27.56
96	Royster Company	Mulberry, Florida			29.49
4770003000	Kentucky	134,359	tons	@	32.96
102	Stauffer Chemical Co	LeMoyne, Alabama			28.95
4770003200	Kentucky	44,830	tons	@	30.95
114	U.S. Industrial Chemicals	Desota, Kansas			34.18
4770003000	Kentucky	45,000	tons	@	37.83
		1,137,722			

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TABLE Q-3. EFFECT OF S PRICE CHANGE AT $0.70/MBTU ACFL FOR POWER PLANTS, SMELTERS, AND ACID PLANTS

Eight power plants affected by S price change at $0.70/MBtu ACFL

0785000500	Illinois	Total tons	77,549	tons affected	31,951
1000000050	Texas	Total tons	125,523	tons affected	5,523
1655000300	Florida	Total tons	192,742	tons affected	192,742
3795000350	Pennsylvania	Total tons	72,342	tons affected	35,037
4520000500	Indiana	Total tons	216,721	tons affected	45,000
4770001900	Tennessee	Total tons	301,246	tons affected	80,403
4770003000	Kentucky	Total tons	628,358	tons affected	538,358
5540000250	Missouri	Total tons	108,149	tons affected	10,149

Two smelters affected by S price change at $0.70/MBtu ACFL

Arizona	Houston	Total tons	118,000	tons affected	118,000
New Mexico	Houston	Total tons	299,000	tons affected	299,000
			417,000		
			939,163		
			1,356,163		

Ten acid plants affected by S price change at $0.70/MBtu ACFL

11	Allied Chemical	Hopewell, Virginia			29.39
4770003000	Kentucky	77,508	tons	@	31.73
33	Borden Chemical	Norfolk, Virginia			31.95
4770003000	Kentucky	80,000	tons	@	32.37
56	Gardinier Inc.	Tampa, Florida			28.06
1655000300	Florida	192,742	tons	@	28.29
62	W. R. Grace & Co.	Bartow, Florida			27.70
4770001900	Tennessee	80,403	tons	@	32.33
4770003000	Kentucky	239,597	tons	@	32.96
74	Mobil Oil	Depue, Illinois			25.08
0785000500	Illinois	31,951	tons	@	27.22
5540000250	Missouri	10,149	tons	@	27.56
86	Olin Corporation	Baltimore, Maryland			26.37
3795000350	Pennsylvania	35,037	tons	@	27.27
88	Olin Corporation	Pasadena, Texas			24.15
Arizona	Houston	118,000	tons	@	27.56
New Mexico	Houston	299,000	tons	@	27.56
96	Royster Company	Mulberry, Florida			29.45
4770003000	Kentucky	141,253	tons	@	32.96
114	U.S. Industrial Chemicals	Desota, Kansas			34.18
4520000500	Indiana	45,000	tons	@	34.38
138	El Paso Products	El Paso, Texas			32.01
1000000050	Texas	5,523	tons	@	34.91
		1,356,163			